RNS ANNOUNCEMENT: The information communicated in this announcement contains inside information for the purposes of Article 7 of Regulation 596/2014.

Trinity Exploration & Production plc

("Trinity" or "the Group" or "the Company")

Preliminary Results

Trinity, the independent E&P company focused on Trinidad and Tobago, today announces its unaudited preliminary results for the 12 months ended 31 December 2018.

2018 was a significant year for Trinity with the recommencement of onshore drilling activities, continuation of our low-cost work programme and strengthening of our balance sheet. The maintenance of our high operating margins and increase in production propelled us to exit the year in a strong financial and operational position as evidenced by our Q4 2018 production levels being in excess of 3,000 bopd and our Adjusted EBITDA margin for the year exceeding 30%.

Key Performance Indicators

		FY 2018	FY 2017	Change (%)
Average realised oil price[1]	*USD/bbl*	59.8	48.6	23
Average net production	*bopd*	2,871	2,519	14
Adjusted EBITDA[2]	*USD MM*	19.2	12.7	51
Adjusted EBITDA[3]	*USD/bbl*	18.3	13.8	33
Adjusted EBITDA margin[4]	*%*	30.7	28.0	10
Adjusted EBITDA after SPT & PT[5]	*USD MM*	12.8	10.6	21
Consolidated operating break-even[6]	*USD/bbl*	29.0	28.4	-2
Cash balance	*USD MM*	10.2	11.8	-14
Cash + working capital surplus [7]	*USD MM*	18.1	0.1	18000

1. Realised price: Actual price received for crude oil sales per barrel ("bbl"). A discount is normally applied to the West Texas Intermediate ("WTI") price by The Petroleum Company of Trinidad and Tobago Limited ("Petrotrin") (1 January 2018 – 30 November 2018) and Heritage Petroleum Company Limited ("Heritage") (effective 1 December 2018 to present) to derive the realised price received by Trinity.
2. Adjusted EBITDA (USD MM): Operating Profit before Supplemental Petroleum Tax ("SPT") and Property Tax ("PT") for the period, adjusted for Depreciation, Depletion & Amortisation ("DD&A"), non-cash share option expenses and Other Expenses (derivative hedge instruments)
3. Adjusted EBITDA (USD/bbl): Adjusted EBITDA/Annual production
4. Adjusted EBITDA Margin (%): Adjusted EBITDA/Revenues
5. Adjusted EBITDA SPT and PT (USD MM): Adjusted EBITDA less Supplementary Petroleum Taxes and Property Taxes
6. Consolidated operating break-even: The realised price where Adjusted EBITDA for the entire Group is equal to zero
7. Cash plus working capital surplus: Current assets less Convertible Loan Notes ("CLN") less Trade and other payables less Taxation payable less Derivative financial instrument (CLN and Ministry of Energy and Energy Industries of T&T ("MEEI") is face value of debt, including accrued interest)

Financial Highlights

- Revenues increased by 38% to USD 62.6 million (2017: USD: 45.2 million)
- Adjusted EBITDA increased 51% to USD 19.2 million (2017: USD 12.7 million)
- Adjusted EBITDA margin of 31% (2017: 28%) or USD 18.3/bbl (2017: USD 13.8/bbl)
- Adjusted EBITDA after SPT and PT up 21% to USD 12.8 million (2017: USD 10.6 million)
- Maintained a group operating break-even price below USD 30.0/bbl

- Cash balance of USD 10.2 million (2017: USD 11.8 million) impacted by one-off increase in trade receivables of USD 6.7 million relating to the Petrotrin restructuring. Post the period-end, USD 4.1 million of these outstanding receivables have been collected and full collection of the remaining USD 2.6 million is expected by the end of H1 2019
- Cash plus working capital surplus of USD 18.1 million (2017: USD 0.1 million)

Corporate Highlights

- Balance sheet significantly strengthened with all outstanding debt fully repaid following USD 20 million fundraise which also provided funds for ongoing onshore drilling programme
- Strengthening of Board, with appointment of Nicholas Clayton as Senior Independent Director

Operational Highlights

- The Company's total 2P reserves (Onshore and Offshore) increased to 24.49 million stock tank barrels ("mmstb") (6% increase vs 2017: 23.21 mmstb)
- Driven primarily by 26% increase in onshore reserves following on from a 45% increase in 2017
- Total 2P reserves and 2C resources of 43.26 mmstb at 31 December 2018 (2017: 47.19 mmstb)
- Average production of 2,871 bopd (2017: 2,519 bopd), representing a 14% increase, underpinned by:
    - Drilling of eight new onshore wells efficiently and cost effectively on a turnkey basis
    - 17 recompletions ("RCPs") (2017: 37) including first offshore RCP
    - Increase in active offshore wells producing to 31 (2017: 17)
    - Base production maintenance through a continuous campaign of 143 workovers ("WO") and reactivations (2017: 97).
- Resulted in exit production rate in excess of 3,000 bopd (Q4 2018: 3,205 bopd)
- Contingent upon the prevailing oil price environment, and subsequent investment, net average production for 2019 is expected to be in the range of 3,000 - 3,300 bopd

2018 was a significant year for Trinity with the recommencement of onshore drilling activities, continuation of our low-cost work programme and strengthening of our balance sheet. The maintenance of our high operating margins and increase in production propelled us to exit the year in a strong financial and operational position as evidenced by our Q4 2018 production levels being in excess of 3,000 bopd and our Adjusted EBITDA margin for the year exceeding 30%.

The Fundraise which we completed in July 2018 means that we are fully funded and debt free. Equally importantly, the sustained generation of strong operating cash flows and a consolidated operating break-even below USD 30.0/bbl provides significant downside protection in the event of a decline in the oil price.

We continue to focus on delivering our planned work programme, with our fully funded drilling operations providing near-term production upside, targeting year-on-year production growth of at least 10%. Added to this, as the development effort continues to mature on our TGAL Area development plan, the Company is increasingly excited the project. The TGAL development has the potential to achieve a step change in production and value for the Company as we target our medium-term production goal of 7,500 bopd. Furthermore, we believe there are a number of inorganic growth opportunities that the Company could pursue, and we are well placed to take advantage of any suitable opportunities that may arise.

The broader environment in T&T remains extremely promising. Whilst there have been some one-off challenges in the transition from Petrotrin to Heritage, we are confident that our locally led business model is well suited to the future based on our incumbent position and strong relationships on the ground in T&T.

With average realisations being above USD 50.0/bbl for 2018, the regressive Supplemental Petroleum Tax ("SPT") impacted cash conversion levels. SPT in its current structure is a global anomaly and disadvantages oil producers when compared to gas producers. Trinity, alongside other crude oil producers in T&T, continue to lobby for its reform as was promised by the current Government. We believe that reform would re-calibrate the economics for all crude oil operators in the region while potentially opening up new investment opportunities.

Alongside working towards a more equitable fiscal environment for oil producers, Trinity continues to strive to optimise the economic returns from its asset base; with a determined focus on subsurface analysis, using the best data available and adopting new technological approaches to include high angle or horizontal drilling.

Given the strength of our ongoing work programme and visibility afforded by our balance sheet, we face the future with a growing confidence. We anticipate further strategic opportunities arising in 2019 and are committed to delivering value for all our stakeholders and with our local model, we are ideally positioned to take advantage of such changes.

Bruce Dingwall, CBE, Executive Chairman of Trinity, commented:

"2018 was a significant year for Trinity with the recommencement of onshore drilling activities, continuation of our low-cost work programme and strengthening of our balance sheet. We face the future with a growing confidence, ideally positioned to take advantage of strategic opportunities arising in 2019 for the benefit of all our stakeholders."

All figures for the financial year 2018 are unaudited. The Board of Directors ("The Board") currently expects to publish its annual report and accounts for the year to 31 December 2018 before the end of April 2019, with the Annual General Meeting ("AGM") expected to take place during May 2019.

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About Trinity (www.trinityexploration.com)
Trinity is an independent oil and gas exploration and production company focused solely on Trinidad and Tobago. Trinity operates producing and development assets both onshore and offshore, in the shallow water West and East Coasts of Trinidad. Trinity's portfolio includes current production, significant near-term production growth opportunities from low risk developments and multiple exploration prospects with the potential to deliver meaningful reserves/resources growth. The Company operates all of its nine licences and, across all of the Group's assets, management's estimate of 2P reserves as at the end of 2018 was 24.5 mmbbls. Group 2C contingent resources are estimated to be 18.8 mmbbls. The Group's overall 2P plus 2C volumes are therefore 43.3 mmbbls.

Trinity is quoted on the AIM market of the London Stock Exchange under the ticker TRIN.

Executive Chairman's Statement

Strategy

Trinity's aim is to position itself as the leading independent producer in T&T on market. To achieve this, our strategy is simple; to retain the integrity of the core producing proved and probable ("2P") reserves base, to continue to grow production safely, to efficiently deliver profitable returns and to prudently convert our significant contingent ("2C") resources to 2P reserves and future inventory.

Delivering production growth whilst sustaining a low operating break-even

Trinity's focus in recent years has been on preserving the integrity of our producing asset base whilst improving operational practices and efficiencies to materially re-base costs. 2018 was the first year since 2013 that Trinity undertook new onshore drilling, with two new wells in H1 and six new wells in H2. The resulting production growth, and improved crude oil prices, had a positive impact on our revenues in 2018. As we progress into 2019, the financial impact of higher base production and new production growth from our continuing drilling programme should become even more apparent.

Average production volumes grew in aggregate by 14% to 2,871 bopd in 2018 (2017: 2,519 bopd). With increased activity levels during H2 2018 there was a 15% quarter on quarter increase in average production volumes to 3,205 bopd for Q4 2018 (Q3 2018: 2,734 bopd). The increase in annualised production was underpinned by a combination of eight new onshore development wells coming on stream during 2018, an increase in active offshore wells producing from 17 to 31 and the continuation of the Group's low-cost ongoing work programme of RCPs, WOs, reactivations and swabbing. The 2018 work programme included a total of 17 RCPs (2017: 37), and 143 WOs and reactivations (2017: 97). On the East Coast, the first offshore RCP on the Trintes field was undertaken by Trinity since assuming operatorship in 2013. It was successfully completed during Q4 2018 and put on production at a rate ahead of management's expectations.

Financial Performance

The result of the 14% growth in production volumes and 23% improvement in oil prices was a 38% increase in revenues to USD 62.6 million (2017: USD 45.2 million). This resulted in a strong operating performance with a 51% increase in Adjusted EBITDA to USD 19.2 million (2017: USD 12.7 million) which is the equivalent of USD 18.3/bbl (2017: USD 13.8/bbl) and US 5.4 cents per share (diluted) (2017: US 3.2 cents) representing a 69% year-on-year increase.

However, bottom-line profitability and cash conversion was negatively affected by the application of SPT which is a regressive tax on net revenues when realised oil prices are above USD 50.0/bbl (2018 average realisations of USD 59.8/bbl vs 2017 of USD 48.6/bbl). The like-for-like comparison of Adjusted EBITDA after SPT and PT was USD 12.8 million (USD 12.2/bbl) for 2018, a 21% increase versus USD 10.6 million (USD 11.6/bbl) for 2017, which equated to a 33% year-on-year increase in Adjusted EBITDA after Taxes of US 3.6 cents per share (diluted) (2017: 2.7 cents).

Operating Cash Flow ("OCF") for 2018 was USD 12.1 million (2017: USD 8.7million). Net OCF after changes in working capital movements and income taxes was USD 5.2 million (2017: USD 9.6 million). The reduction is mainly a function of a USD 4.4 million year-on-year increase in cash taxes paid (largely related to SPT) and an increase in trade receivables totalling USD 6.7 million. The increase in trade receivables was due to delayed revenue receipts of USD 6.7 million as a result of the Petrotrin restructuring (see details below). Post the year end, USD 4.1 million of the outstanding receivables from Petrotrin have been collected and full collection of the remaining USD 2.6 million is expected to occur by the end of H1 2019. Stripping out the increase in receivables, the like for like OCF after changes in working capital would have been USD 11.8 million versus USD 9.6 million for 2017.

The Group's cash balances at the year-end stood at USD 10.2 million (2017: USD 11.8 million). The lower cash balance is as a result of capital expenditures of USD 12.5 million (2017: USD 3.1 million) and the repayment of all outstanding debts to Board of Inland Revenue of T&T ("BIR") and Ministry of Energy and Energy Industries of T&T ("MEEI") (together "T&T State Creditors") and Convertible Loan Notes ("CLN") holders (USD 5.8 million and USD 7.2 million respectively). However, importantly, the Company is now debt free, with no dilutive CLN overhang, and has the financial flexibility required to grow by the most effective means. In aggregate, the resultant cash plus working capital surplus (cash plus net operating working capital) stood at an impressive USD 18.1 million (2017: USD 0.1 million)

Reserve base continues to grow

Management's estimate of the Company's total 2P reserves (Onshore and Offshore) increased by 6% to 24.49 million stock tank barrels ("mmstb") (2017: 23.21 mmstb), despite total production of 1.04 mmstb. This increase is testament to the quality of our onshore and offshore producing assets and the benefits of the return to robust subsurface evaluation to identify additional infill drilling, RCP and WO candidates. Onshore reserves grew significantly by 26%, following on from a 45% increase in 2017 as the subsurface team continued to add locations to the onshore drilling inventory.

2C resources decreased by 22% to 18.77 mmstb (2017: 23.98 mmstb). The movement in 2C resources primarily reflects moving some 5.98 mmstb (net) of TGAL resources to 3C until a formal development solution is finalised. This follows the high grading of a first phase development stage targeting 10.41 mmstb (net) with more robust overall economics. In aggregate, total 2P reserves and 2C resources amounted to 43.26 mmstb at 31 December 2018 (2017: 47.19 mmstb).

Corporate

Funded and Debt Free
In July 2018 the Company raised gross proceeds of USD 20.0 million through a Fundraising exercise comprising a placing and an open offer. Of this, USD 6.4 million comprised a non-cash rollover by holders of 88% of the CLNs electing to convert the value of their CLNs into new ordinary shares at the issue price. This enabled the full and final repayment of all outstanding debts to the T&T State Creditors as well as redemption of the remaining CLNs which were outstanding. The Fundraise has enabled the Company to accelerate its onshore drilling programme and production, with a planned 8-10 wells per year going forward subject to a conducive landscape and economic environment.

East Coast Asset Development
In November 2018 the Company, as operator of the Galeota licence, submitted the first phase of its revised Field Development Plan ("FDP") for the TGAL Area to the MEEI. Work is now ongoing on pre-Front End Engineering Design ("FEED") studies and environmental approvals as we move towards a Final Investment Decision ("FID") during H1 2020.

This FDP is the first phase of a potential wider development strategy moving across the Galeota anticline to fully develop the reserves potential from the large volumes of oil in place (c. 700 mmbbls). The first phase currently contemplates the installation of a low cost, 10 well conductor supported platform, the installation of a new generation thermoplastic composite subsea export pipeline, the laying of a subsea power cable to provide power to the offshore facilities, and the drilling of horizontal production wells. The development of these assets would underpin our medium-term group onshore and offshore production target of over 7,500 bopd.

Petrotrin Restructuring and Heritage Update

On 28 August 2018 Petrotrin announced its intention to discontinue refining operations to focus on its upstream exploration and production activities following a restructuring. To that end the new national oil company, Heritage began trading on 1 December 2018. Whilst the transition has been relatively seamless with regards to production, supply and distribution, there have been delays in the timing of payments for October and November oil production from Petrotrin. As a result, Trinity's receivables increased by USD 6.7 million at the year end. To date, USD 4.1 million of the USD 6.7 million delayed revenues have been collected and under Heritage's stewardship since December 2018 all payments have been received according to the agreed payment terms. The management of both Petrotrin and Heritage have been in close contact with Trinity's management team and have provided the requisite comfort that all outstanding revenues will be received in full during H1 2019.

Trinity currently accounts for approximately 5% of all crude oil production in T&T and we are optimistic of our ability to deliver continued production growth in the short-term. Having established a locally driven, efficient and low-cost operating model, Trinity will work alongside Heritage wherever possible to help facilitate efficiency drives and production growth in T&T with the resultant economic benefits for all citizens and stakeholders.

Overview

This time last year our aim was to stabilise base production, build well inventory and execute a limited investment programme whilst maintaining controls on operating costs and Health, Safety, Security and Environment ("HSSE"). The Company managed to deliver on that initial programme resulting in a significant improvement in our operational performance and a successful year in terms of our key performance indicators ("KPIs").

During 2018, we continued to prioritise HSSE and the well-being of our people, promoting safe behaviours among all stakeholders whilst undertaking a step-change in activity levels. The dedication, hard work and expertise to deliver this growth on a portfolio of 1,094 wells with 216 active wells at the end of 2018 (2017:182) across nine licences and multiple reservoirs has required a huge effort from those involved. As such, we remain extremely thankful to our employees and the continued support of the supply chain, with whom we look forward to working alongside as we continue to build on, and strengthen relationships with all of our stakeholders.

We are ideally placed to continue to grow organically but also very well positioned to make the most of the significant number of other development opportunities that may arise locally. Whilst we work with the Petrotrin restructuring and transition changes with Heritage, we are assured that our locally led business model is well suited to the future based on our strong relationships on the ground in T&T.

Good governance remains at the core and we remain committed to delivering our strategy in a responsible and transparent manner. In November 2018, the Company expanded its Board with the appointment of Nicholas Clayton as a Senior Independent Director. The breadth and depth of his sector specific advisory experience will provide the Board with additional perspective and, combined with our existing Board members, strengthens our collective industry, merger and acquisitions ("M&A") and capital markets expertise as we continue to grow and develop Trinity's business.

Plans for 2019 and beyond

We are ideally placed to continue to grow organically but also very well positioned to make the most of the significant number of other development opportunities that may arise locally. Whilst we look forward to working with Heritage going forward, we are assured that our locally led business model is well suited to the future based on our strong relationships on the ground in T&T.

The Company's successful drilling programme completed during Q4 means that it fulfilled stated >10% per annum ("p.a.") production growth target for 2018 and, subject to the scheduling of the drilling programme, Trinity is targeting similar growth in 2019. The fully funded onshore drilling programme will continue, but given recent oil price volatility, the timing and scale of the programme will be determined with a view to optimising capital allocation.

We see a number of options for further value creation across Trinity's asset base both organically and from wider portfolio management. Our programme of phased and risk mitigated development activities through infill development wells onshore, routine RCPs, WOs, reactivations and swabbing on the current well stock has succeeded in arresting decline and provided for a step-change in base production on which to further grow.

The Company intends to build on base production to reach a targeted annual average production range of 3,000 – 3,300 bopd for 2019. The absolute level of growth from production will be determined by oil price and activity levels which will be set with a view to optimising profitability and cash flows, and not just top-line production growth.

The Company's strengthened balance sheet and low operating break-even provides financial resilience to low oil prices and gives confidence that the Company's growth and investment plans can be optimised according to the prevailing macro and fiscal environment.

On behalf of the Board, I must thank all our staff and suppliers in T&T for their diligence, commitment and support which has allowed Trinity to focus on growth whilst maintaining a safe working environment. The Board would additionally like to take this opportunity to thank existing shareholders and other stakeholders, notably Petrotrin, Heritage, BIR, and the MEEI, for their support and to welcome new shareholders as we move forward debt free and strongly positioned to add value from future opportunities in the changing environment in T&T.

2018 was a notable year for Trinity and the Board is confident that the quality and low cost nature of our underlying assets will deliver sustainable cash generation throughout oil price cycles and excellent returns for shareholders from the execution of our strategy in 2019 and beyond.

KEY PERFORMANCE INDICATORS

The Group's performance was profitable at an operating level throughout 2018 with a 51% increase in Adjusted EBITDA of USD 19.2 million (2017: USD 12.7 million), year-end cash balance of USD 10.2 million (2017: USD 11.8 million) and a cash plus working capital surplus of USD 18.1 million (2017: USD 0.1 million).

A summary of the year-on-year operational and financial highlights are set out below:

		FY 2018	FY 2017	Change (%)
Average realised oil price[1]	*USD/bbl*	59.8	48.6	23
Average net production	*bopd*	2,871	2,519	14
Annual production[2]	*mmbbls*	1.05	0.92	14
Revenues	*USD MM*	62.6	45.2	38
Adjusted EBITDA[3]	*USD MM*	19.2	12.7	51
Adjusted EBITDA[4]	*USD/bbl*	18.3	13.8	33
Adjusted EBITDA margin[5]	*%*	30.7	28.0	10
Adjusted EBITDA Per Share - Diluted[6]	*US cents*	5.4	3.2	69
Adjusted EBITDA after SPT and PT[7]	*USD MM*	12.8	10.6	21
Adjusted EBITDA after SPT and PT[8]	*USD/bbl*	12.2	11.6	6
Adjusted EBITDA after SPT and PT Per Share - Diluted[9]	*US cents*	3.6	2.7	33
Consolidated operating break-even[10]	*USD/bbl*	29.0	28.4	-2
Cash balance	*USD MM*	10.2	11.8	-14
Cash plus working capital surplus[11]	*USD MM*	18.1	0.1	18000

1. *Realised price: Actual price received for crude oil sales per barrel ("bbl"). A discount is normally applied to the West Texas Intermediate ("WTI") price by Petrotrin (1 January 2018 – 30 November 2018) and Heritage (effective 1 December 2018 to present) to derive the realised price received by Trinity.*
2. *Annual production (mmbbls)- Production from a reserves perspective is what is produced from the reservoir in a given year - which is 1.04 mmbbls (2,855 bopd) in 2018. For cash flow purposes it is the sold production in a given year which for 2018 is 1.05 mmbbls (2,871 bopd). These minor differences occur at year end due to stock sales in December and carry forward to subsequent year. See Reserves and resources section for further details.*
3. *Adjusted EBITDA (USD MM): Operating Profit before SPT and PT for the period, adjusted for Depreciation, Depletion & Amortisation ("DD&A"), non-cash share option expenses and Other Expenses (derivative hedge instruments)*
4. *Adjusted EBITDA (USD/bbl): Adjusted EBITDA/Annual production*
5. *Adjusted EBITDA Margin (%): Adjusted EBITDA/Revenues*
6. *Adjusted EBITDA Per Share – Diluted: Adjusted EBITDA / Weighted average ordinary shares outstanding - diluted*
7. *Adjusted EBITDA after SPT and PT (USD MM): Adjusted EBITDA less Supplementary Petroleum Taxes ("SPT") and Property Taxes ("PT")*
8. *Adjusted EBITDA after SPT and PT (USD/bbl): Adjusted EBITDA after SPT and PT/Annual production*
9. *Adjusted EBITDA after SPT and PT Per Share – Diluted: Adjusted EBITDA after SPT and PT / Weighted average ordinary shares outstanding – diluted*
10. *Consolidated operating break-even: The realised price where Adjusted EBITDA for the entire Group is equal to zero*
11. *Cash plus working capital surplus: Current assets less CLN less Trade and other payables less Taxation payable less Derivative financial instrument (CLN and MEEI is face value of debt, including accrued interest)*

ADJUSTED EBITDA CALCULATION

Adjusted EBITDA is a non-IFRS measure used by the Group to measure business performance. The Group presents Adjusted EBITDA metrics as they are used in assessing the Group's growth and operational efficiencies as they better illustrate the underlying performance of the Group's business by excluding items not considered by management to reflect the underlying operations of the Group.

	2018	**2017**
	USD MM	**USD MM**
Operating Profit before SPT and PT	6.7	3.9
DD&A	10.7	7.1
Share option expenses	0.7	0.2
Other Expenses (derivative hedge instruments)	1.1	1.4
Adjusted EBITDA	**19.2**	**12.6**
Less: SPT and PT	(6.4)	(2.0)
Adjusted EBITDA after SPT and PT	**12.8**	**10.6**
Expressed in US cents		
Adjusted EBITDA Per Share – diluted	5.4	3.2
Adjusted EBITDA after SPT and PT per Share – diluted	3.6	2.7

See Note 22 to Consolidated Financial Statements – Adjusted EBITDA for further details

2018 TRADING SUMMARY

A 5-year historical summary of realised price, production, operating break-evens and Production Costs ("Opex") and General & Administrative ("G&A") expenditure metrics is set out below:

Details	**2014**	**2015**	**2016**	**2017**	**2018**
Realised Price (USD/bbl)	85.8	45.5	39.4	48.6	59.8
Production (bopd)					
Onshore	2,005	1,601	1,343	1,347	1,563
West Coast	491	312	190	212	198
East Coast	1,105	983	1,009	961	1,110
Consolidated	3,601	2,896	2,542	2,519	2,871
Operating Break-Even (USD/bbl)[1]					
Onshore	21.3	23.3	17.4	16.6	16.1
West Coast	24.5	40.7	37.7	26.6	26.8
East Coast	55.9	41.3	26.3	24.9	25.9
Consolidated[2]	64.3	47.2	29.2	28.4	29.0
Metrics (USD/bbl)					
Opex/bbl - Onshore	14.4	15.7	11.8	11.1	11.7
Opex/bbl - West Coast	20.2	33.8	31.6	22.1	22.1
Opex/bbl - East Coast	41.6	31.6	20.1	18.9	20.1
G&A/bbl - Consolidated[3]	11.3	9.6	4.4	4.4	5.0

Notes:

1. *Operating Break-even: The realised price where Adjusted EBITDA for the respective asset or the entire Group (Consolidated) is equal to zero*
2. *Consolidated Operating Break-even: Includes G&A but excludes share option expenses*
3. *G&A/bbl – Consolidated: Excludes share option expenses*

The above production trends show clearly the impact that returning to drilling has had with Onshore production up over 16% year-on-year despite the new drilling mainly impacting in the final quarter of the financial year. Similarly, the impressive impact of active production and well management offshore the East Coast has been to deliver a five year average volume of 1,033 bopd and a very stable platform from which to grow when development recommences on the East Coast.

Of particular note from a financial standpoint is that robust constituent asset and corporate level operating break-evens were sustained with an aggregate increase of only 2% in the Group consolidated operating break-even to USD 29.0/bbl (2017: USD 28.4/bbl). The consolidated operating break-even includes the Group's G&A costs and therefore captures the corporate costs associated with supporting the asset base.

At the aggregated corporate level the maintenance of such a robust consolidated operating level break-even reflects higher production volumes offsetting higher expenses as detailed below:

- Overall Opex increased by 21% to USD 17.8 million (2017: USD 14.7 million). This variance was largely a function of a larger WO programme, production optimisation and increased vessel and equipment rental from higher activity levels.
- G&A costs increased by 40% to USD 6.0 million (2017: USD 4.3 million). This is predominately a function of non-cash related expenses (unrealised foreign exchange gain USD (0.0) million (2017: USD (0.5) million) and share option expenses USD 0.7 million (2017: USD 0.3 million)) as well as increased staff costs, levies and corporate expenses.

Operating netback (Revenues minus Royalties and Production costs) increased 47% to USD 24.4 million (2017: USD 16.7 million). On a per barrel basis this represents a 33% increase in operating netback to USD 23.4/bbl (2017: 17.6/bbl).

OPERATIONAL REVIEW

OUR PEOPLE

Trinity's workforce stood at 215 (2017: 188) at the year-end December 2018 with 79% (170) male and 21% (45) female employees. Our employees are located both in the United Kingdom ("UK") and T&T, with the majority (97%) based in T&T at our core operations.

HEALTH, SAFETY, SECURITY & ENVIRONMENT ("HSSE")

Trinity continues to place HSSE at the forefront of our operations as we strive towards further improving our safety performance by ongoing sensitisation, training, increased monitoring, frequent reviews of our internal controls and implementing corrective action when necessary.

The Board is fully apprised of the Company's HSSE performance via quarterly updates. The HSSE report is considered at each Board meeting and is one of the first matters considered on the agenda.

Management's commitment to the See, Think, Act, Reinforce and Track ("START") card programme has positively impacted our HSSE culture. Behaviour based safety has been recognised as an integral factor in our drive to an incident free environment. Notable improvements in our HSSE performance were achieved due to our continued emphasis on a strong HSSE culture, facilitated by an increase in management visits to all assets, increased communication of lessons learned and several proactive initiatives implemented across all operations. Trinity recorded 643,400 man hours in 2018 (2017: 486,200 man hours), a 32% increase, mainly due to the 2018 work programme which included onshore drilling as well as onshore and offshore RCPs and workovers. Training hours recorded also saw an increase of 14% to 2,718 hours from 2,384 hours as safety remained as a top priority to Trinity to ensure that employees are competent to execute all tasks in a safe and efficient manner.

Trinity continues to build its HSSE management system as per our Safe to Work ("STOW") T&T certification attained in February 2018 from the Energy Chamber of T&T. The renewal process and audit commences in Q3 2019 in preparation for recertification in February 2020. Trinity was able to attain a two year certification within a four month period which surpassed the 6-12 month standard process. This is considered a great achievement since new companies to the STOW T&T certification process rarely achieve a two year certification. This certification provides the assurance that our HSSE management system is developed in such a form to allow us to have the ability to respond, control and analyse safety events and performance data as well as allowing us to be proactive in mitigating and managing risk. Notwithstanding our 2018 achievements, in 2019 Trinity intends to continue its focus on sustaining and improving our HSSE management system to ensure that we deliver our production targets safely and efficiently.

PRODUCTION

Average net production for 2018 was 2,871 bopd (2017: 2,519 bopd), an increase of 14%. A total of eight new infill development wells, 17 RCPs, 143 WOs and reactivations along with swabbing activities were undertaken during 2018.

We are constantly striving towards re-setting base production upwards**.** This requires continuous efforts, good acreage and the application of new technologies. An overview of these activities by asset is given below.

Onshore Assets

Current Onshore production is from Lease Operatorship Blocks: FZ-2, WD-2, WD-5/6, WD-13, WD-14 and Farmout Block: Tabaquite.

Average 2018 net production from the Onshore assets was 1,563 bopd which accounted for 54% of total annual average production. This represented a 16% increase in production from the 2017 average net production levels of 1,347 bopd. The growth in year-on-year production averages is reflective of the step-change in investment activities beginning to impact in adding new production whilst simultaneously successfully maintaining base production.

The drilling programme carded for 2018 initially consisted of four new infill wells. The first two wells were drilled in H1 2018 before expanding the campaign by drilling a further six wells in H2 2018.

Trinity's RCP campaign contemplated the completion of 12 RCPs onshore. The programme was executed in the first 10 months of the year, eventually recompleting 16 wells (2017: 37) across all Onshore blocks. The RCPs and WOs were executed utilising Trinity's internal rigs through H1, while contracting two rigs for the remainder of the year. The internal rigs were removed from service during H2 for upgrades and overhaul.

The Onshore WO and reactivations campaign contemplated the completion of 84 WO's onshore. For 2018, 113 were completed (2017: 78).

Going forward, the Company intends to continue with development activities via infill development drilling, RCPs, WOs, reactivations and swabbing on the current well stock and identified drilling locations to maintain base production and provide for further production growth.

East Coast Assets

Current East Coast production is derived from the Alpha, Bravo and Delta platforms in the Trintes Field which sits within the Galeota Block.

Average 2018 net production from the East Coast was 1,110 bopd which accounted for 39% of total annual average production. This represented a 16% increase in production from the 2017 average net production levels of 961 bopd. The increase was largely as a result of the successful execution of a rigorous workover and reactivation campaign. Alongside these activities the successful completion of the first RCP undertaken by Trinity since assuming operatorship in 2013 was undertaken during Q4 2018 and put on production at a rate ahead of Management's expectations.

In 2018, 23 restorative WOs were completed (2017: 18) which contributed to an upward trend in production. In 2018 production was derived from 32 of a possible 61 wellbores in the Trintes field. The Trintes field produced by deploying numerous pumping technologies across our well stock including; Mechanical Pumping Hydraulic Unit ("MPHU"), Hydraulic Diaphragm Electric Submersible Pump ("HDESP"), Electric Submersible Pump ("ESP") and Progressing Cavity Pumps ("PCP"). The team continues to explore further means of optimising production through the utilisation of downhole remote monitoring, chemical treatment for the prevention of scale formation and modified artificial lift technologies.

Various infrastructure projects were undertaken during 2018 which included crane assessment and recertification works, the acquisition of four new generators, accommodation upgrades and the commencement of phase 1 Front-End Engineering Design ("FEED") process for the installation of a new 10,000 bbl oil storage tank at the Galeota tank farm.

Trinity continues to invest in stabilising production levels via better generator maintenance strategies and continued optimisation of alternative artificial lift technologies to augment production rates and maintain efficiency and cost effectiveness.

West Coast Assets

West Coast production is from the Point Ligoure-Guapo Bay-Brighton Marine ("PGB") and Brighton Marine ("BM") fields.

Average 2018 net production from the West Coast was 198 bopd which accounted for 7% of total annual average production. This represented a 6% decrease in production from 2017 average levels of 212 bopd and was mainly as a result of natural production decline.

There were no major production related activities conducted on the West Coast assets in 2018, with the exception of three WOs (2017: one) in the PGB field and four WO (2017: one) on the land-based wells in the Brighton Field which were undertaken with the intention of reducing natural production decline and stabilising base production levels. Minor infrastructural works were undertaken on the offshore platforms to maintain asset integrity and production.

Management are continuing to keep the potential sale of the West Coast assets under review. In the interim, the assets continue to generate positive cash flow and going forward the land based wells across both the PGB and BM fields will be targeted for reactivations in addition to minor facility upgrades to increase production. These assets will continue to be closely monitored as progressive steps are taken to further optimise production through swabbing and minimal well intervention at low operating costs.

RESERVES AND RESOURCES

A comprehensive management review of all assets has been concluded and has estimated the current 2P reserves to be 24.49 mmstb at the end of 2018, compared to the year-end 2017 reserve estimate of 23.21 mmstb. This represents a 6% increase of 1.28 mmstb from 2017 levels, despite production for 2018 of 1.04 mmstb (2017: 0.92 mmstb). This increase reflects contributions from new wells, sustained RCP production, updated decline curve analysis on producing wells, low cost well reinstatements and, most significantly, extensive subsurface work to generate additional infill drilling, RCP and WO candidates.

Onshore reserves grew by 26% as a result of our ongoing continued investment in subsurface analysis. This follows on from a 45% increase delivered in 2017. Management considers this to be the best estimate of the quantity of reserves that will actually be recovered from the assets at the end of 2018. It represents production which is commercially recoverable, either to licence/relevant permitted extension end or earlier via the application of the economic limit test.

The subsurface review has defined investment programmes and constituent drilling targets to commercialise the reserves as detailed, by asset area, in the table below:

Unaudited 2018 2P Reserves

Asset Net Oil Production	31 December 2017 mmstb	Production (*) mmstb	Revisions mmstb	31 December 2018 mmstb
Onshore	5.78	(0.56)	2.08	7.30
East Coast	14.78	(0.41)	0.43	14.80
West Coast	2.65	(0.07)	(0.19)	2.39
Total	23.21	(1.04)	2.32	24.49

Note (*): Production from a reserves perspective is what is produced from the reservoir in a given year-in this case 2,855 bopd. For cash flow purposes it is the sold production in a given year and this figure is given elsewhere as 2,871 bopd. These minor differences occur at year end due to stock sales in December and carry forward to subsequent year.

The best estimate of 2C resources due to the current economic environment and the defining technical work pending is estimated by management at 18.77 mmstb (2017: 23.98 mmstb).

Unaudited 2018 2C Resources

Asset	31 December 2017 mmstb	Revisions mmstb	31 December 2018 mmstb
Onshore	2.18	(0.68)	1.50
East Coast	20.87	(4.49)	16.38
West Coast	0.93	(0.04)	0.89
Total	23.98	(5.21)	18.77

Unaudited Summary of Reserves and Resources
at 31 December 2018

Asset	2P Reserves mmstb	2C Resources mmstb	2P+2C Reserves and Resources mmstb
Onshore	7.30	1.50	8.80
East Coast	14.80	16.38	31.18
West Coast	2.39	0.89	3.28
Total	24.49	18.77	43.26

EAST COAST

Trintes (Trinity: 100% WI)

On the East Coast, Trinity has an established production hub on the Trintes field with 4 offshore marine platforms; (Alpha, Bravo, Charlie & Delta) that have an aggregate of 61 platform wells. Current 2P reserves underpin only the producing Trintes field. However, across the East Coast Galeota anticline licence area, Management estimates total gross Stock Tank Oil Initially In Place ("STOIIP") of over 700 mmstb of which 249 mmstb of STOIIP is mapped against the Trintes field. Trintes (current booked East Coast) 2P reserves of 14.8 mmstb therefore represents a low incremental recovery factor of 6%. Within contingent resources a further 5.96 mmstb relates to the Trintes field.

TGAL Field Development Plan (Trinity: 65% WI)

The TGAL area carries an internal best estimate STOIIP of 186 mmstb. The TGAL updip fault panel was confirmed as oil bearing in all major reservoir horizons by the TGAL-1 discovery well and is now incorporated in the 2018 FDP. In November 2018 the first phase of the FDP for the TGAL Area, located on the Galeota Block (updip from and on the same anticline as the Trintes field), was submitted to the MEEI. This FDP is the first phase of a potential wider step-out development moving across the Galeota anticline to fully develop the reserves potential from the large volumes of oil in place (see Reserves & Resources review for further details).

Work is progressing on FEED studies and environmental approvals as we move towards a FID during H1 2020, at which time the optimal scheme for financing the development will have been selected and agreed between all stakeholders. The 2018 FDP envisages 10 wells and is a lower development cost solution targeting the deeper sands using vertical conductors when compared to scheme outlined in the 2015 FDP which previously outlined 17 wells and the following key features:

- Conductor Support Platform ("CSP") designed to accommodate a platform rig
- 25 year design life
- A 6" ID Thermoplastic Composite Pipeline ("TCP") from the TGAL platform to shore
- Subsea power cable from shore to the platform
- First oil estimated being produced by H1 2022 and peak production estimated at 5,800 bopd
- 2C resources c.16.02 mmstb gross (10.41 mmstb net)
- At FID Trinity anticipate the net 2C resources would be reclassified as 2P reserves

This 2018 FDP is viewed as the first phase of a potential broader development moving across the Galeota anticline to commercialise the reserves potential from the large volumes of oil in place (c. 700 mmstb). The shallow sands (which were to be accessed via 7 wells in the 2015 FDP) but necessitate drilling slanted conductors/drilling have been moved to the 3C category (9.20 mmstb gross, 5.98 mmstb net) pending the integration of a technical solution into the current vertical conductor CSP platform concept. The current TGAL total 2C+3C volumes are therefore 25.22 mmstb (16.4 mmstb net). Within the Galeota anticline licence area there is also significant additional prospectivity with 266 mmstb STOIIP having been mapped over and above the Trintes and TGAL areas. Even excluding this further upside potential, with current combined 2P reserves and 2C resources of 32.68 mmstb, the potential growth from future Trintes drilling and TGAL development is substantial.

FINANCIAL REVIEW

This consolidated financial information has been prepared on a going concern basis, in accordance with International Financial Reporting Standards ("IFRS") as adopted by the European Union ("EU"), IFRS Interpretations Committee ("IFRS IC") interpretations as adopted by the EU and those parts of the Companies Act 2006 as applicable to companies reporting under IFRS. This consolidated financial information has been prepared under the historical cost convention, modified for fair values under IFRS. The Group's accounting policies and details of accounting judgements and critical accounting estimates are disclosed within Note 3 of the Financial Statements. The Group has adopted additional accounting policies in the year ended 31 December 2018 as set out in Note 3 of the Financial Statements.

Throughout this report reference is made to adjusted results and measures. The directors believe that the selected adjusted measures allow management and other stakeholders to better compare the normalised performance of the Group between the current and prior year, without the effects of one-off or non-operational items and better reflects the normalised underlying cash earnings achieved in the year. In exercising this judgment, the directors have taken appropriate regard of International Accounting Standards ("IAS") 1 "Presentation of financial statements". For the reasons stated above, Adjusted EBITDA excludes the impact of DD&A, non-cash share option expenses, and the impact of derivative hedge instruments ("adjustment items") and these are summarised on the face of the Consolidated Income Statement as well as being described in Note 22 to the financial statements.

Results for the year

Trinity and its subsidiaries ("the Group") recorded an Adjusted EBITDA of USD 19.2 million (2017: USD 12.6 million), a reported loss for the year of USD (5.3) million (2017: USD 25.4 million profit), an ending cash balance of USD 10.2 million (2017: USD 11.8 million) and a net cash plus working capital surplus position of USD 18.1 million (2017: USD 0.1 million).

- **Revenue growth from increased production and oil price realisations:** The combination of a 14% increase in production to 2,871 bopd (2017: 2,519 bopd) and a 23% increase in average oil price realisations to USD 59.8/bbl (2017: USD 48.6/bbl) resulted in a 38% increase in revenues to USD 62.6 million (2017: USD 45.2 million).

- **Successful capital expenditure work programme:** USD 12.5 million (2017: USD 3.1 million) incurred in predominately production related and infrastructure expenditure. 2018 saw the company return to drilling, with 8 Onshore development wells, 16 Onshore RCP's and the first RCP on the East Coast since acquiring the asset in 2013. Infrastructure capital expenditure were also conducted across the assets to support the production initiatives.

- **Further growth in operating margins and increased operating profitability:** The Company maintained its focus on growing margins and increasing operating profitability which is evident in a 51% increase in Adjusted EBITDA to USD 19.2 million (2017: USD 12.7 million) and maintaining a robust consolidated operating break-even price of USD 29.0/bbl (2017: USD 28.5/bbl), while increasing Adjusted EBITDA Margin to 31% in 2018 (2017: 28%). On a per barrel basis this represents a 33% increase in Adjusted EBITDA to USD 18.3/bbl (2017: USD 13.8/bbl) and Adjusted EBITDA per share - diluted increased 69% to 5.4 cents (2017: 3.2 cents).

- **Supplementary Petroleum Taxes ("SPT") and Property Taxes ("PT"):** 2018 saw average oil price realisations rise above USD 50.0/bbl (2018: USD 59.8/bbl) into the SPT paying range. As a result, SPT of USD 7.1 million was incurred in 2018 (2017: USD 1.5 million). For each quarter that realised oil prices are higher than USD 50.01/bbl SPT is charged at a rate of 18% and 26% on net revenues (gross revenue – royalties – incentives) on Onshore and Offshore assets respectively. The headline

SPT rates are, however, partially mitigated by investment tax credits of 20%. SPT is seen by many commentators as being a regressive tax, which negatively impacts on investment and unfairly penalises oil (as opposed to gas) companies. SPT reform has been earmarked by the Government of Trinidad and Tobago ("GORTT"), but has not yet been effected.

The passing of the Property Tax Amendment Bill by the T&T House of Representatives resulted in a PT credit of USD 0.7 million (2017: USD (0.5) million charge) with the USD 1.1 million reversal for 2016 and 2017 offsetting a USD 0.4 million charge for the current year.

- **Impairment loss:** During the year the Group recorded an impairment loss of USD 2.6 million (2017: nil) within exceptional items on its oil and gas assets held within property plant and equipment. The carrying values of certain of the Group's cash generating units were higher than their recoverable amount measured utilising discounted cash flow approach to Fair Value less Cost of Disposal. This was largely driven by the lower oil price forward curve at 31 December 2018, and a more conservative cost of capital assumption being applied.

- **Reported Profitability and Cash conversion:** Bottom-line profitability and cash conversion was negatively impacted by SPT. The like for like comparison of Adjusted EBITDA after SPT and PT is USD 12.8 million (USD 12.2/bbl and 3.6 cents per share - diluted) for 2018 versus USD 10.6 million (USD 11.5/bbl and USD 2.7 cents per share - diluted) for 2017.

  The inclusion of DD&A, hedging costs, other non-cash items, exceptional items and net finance costs yielded a reported post tax loss for the period of USD 5.3 million (2017: USD 25.4 million profit). Notably, in 2017 there was an exceptional non-cash credit of USD 26.7 million, which related to the restructuring that occurred in January of that year.

Operating Cash Flow ("OCF") for 2018 was USD 12.1 million (2017: USD 8.7million). Net OCF after changes in working capital movements and income taxes was USD 5.2 million (2017: USD 9.6 million). The reduction is mainly a function of a USD 4.4 million year-on-year increase in cash taxes paid (largely related to SPT) and an increase in trade receivables totalling USD 6.7 million. The increase in trade receivables was due to delayed revenue receipts of USD 6.7 million as a result of the Petrotrin restructuring (see details below). Post the year end, USD 4.1 million of the outstanding receivables from Petrotrin have been collected and full collection of the remaining USD 2.6 million is expected to occur by the end of H1 2019. Stripping out the increase in receivables, the like for like OCF after changes in working capital would have been USD 11.8 million versus USD 9.6 million for 2017.

- **Strong net cash plus working capital surplus:** The lower OCF after changes in working capital combined with higher capital expenditure of USD 12.5 million (2017: USD 3.1 million) and the repayment of all outstanding debts to T&T state creditors and CLN holders (USD 5.8 million and USD 7.2 million respectively) pushed down cash balances at year end. Cash balances at the year-end stood at USD 10.2 million (2017: USD 11.8 million). Nevertheless, Trinity had a strong net cash plus working capital surplus of USD 18.1 million (versus USD 0.1 million in 2017). Crucially, the Company is now debt free, with no dilutive CLN overhang, and has the financial flexibility to grow by the most effective means.

- **Mitigating downside price risk:** In 2018, a USD 1.0 million loss was incurred on the crude oil derivative instrument and recorded within Other Expenses which protected against downside oil prices below USD 45.0/ bbl utilising a Zero Cost Collar. For 2018 the WTI price ranged from USD 62.3/bbl to USD 70.7/bbl between January and October 2018. The WTI price traded in a range of USD 59.8/bbl to USD 56.7/bbl in November and USD 49.1/bbl for December 2018, hence no settlements were incurred in those months. This hedge expired on 31 December 2018 and so no hedge valuations are included for the year end financials.

STATEMENT OF COMPREHENSIVE INCOME ANALYSIS

Revenues
2018 crude oil sales revenues were USD 62.6 million (2017: USD 45.2 million). This 38% increase was attributable to a 14% increase in production volumes to 2,871 bopd (2017: 2,519 bopd) and a 23% increase in the average realised oil price to USD 59.8/bbl (2017: USD 48.6/bbl).

Operating expenses
Operating expenses increased by 24% in 2018 to USD (55.9) million (2017: USD (41.2) million). Operating expenses comprised:

- Royalties of USD 20.4 million (2017: USD 13.8 million) have increased due to a combination of increased sales volume and price.
- Production costs of USD (17.8) million (2017: USD (14.7) million) have increased due to more workovers, production optimisation and vessel and equipment costs complimenting the increased activity levels.
- G&A expense of USD (6.0) million (2017: USD (4.3) million), increased mainly due to non-cash share option expense of USD (0.7) million (2017: USD (0.3) million) and unrealised foreign exchange gain USD 0.0 million (2017: USD 0.5 million)
- Depreciation, depletion and amortisation (“DD&A”) of USD (10.7) million (2017: USD (7.0) million).
- Other Expenses of USD (1.0) million (2017: (1.4) million) includes the impact of derivative hedge instruments in relation to the Zero Cost Collar in effect during 2018 USD (1.0) million (2017: USD (0.8) million) and Put Options nil (2017: USD (0.6) million).

Supplemental Petroleum Tax and Property Tax
SPT and PT were USD (6.5) million (2017: USD (2.0) million) and comprised:

- SPT of USD (7.1) million (2017: USD (1.5) million) due to realised oil prices being above USD 50.01/bbl.
- PT credit of USD 0.6 million (2017: USD (0.5) million) which included the current year charge of USD (0.4) million and the reversal of the 2016 and 2017 accrual of USD 1.1 million.

Exceptional items
Exceptional items were USD (2.3) million (2017: USD 25.7 million credit) and comprised:

- Impairment of plant property, equipment, receivables, recompletions and inventory USD (2.6) million (2017: USD (0.6) million).
- Reversal of bad debt USD 0.2 million credit (2017: nil) for recovered VAT refunds in relation to 2013 previously written off.
- Restructuring USD (0.0) million (2017: USD 26.3 million credit).
- Unsecured creditors compromised USD 0.1 million credit (2017: nil) relating to write off of remaining creditor balances compromised.

See Note 6 to Consolidated Financial Statements - Exceptional items for further details. The Group’s operating loss after exceptional items was USD (2.0) million (2017: USD 27.6 million profit).

Net Finance Costs
In 2018, finance costs amounted to USD (2.1) million (2018: USD (2.3) million) and comprised:

- Unwinding of the decommissioning liability USD (1.6) million (2017: USD (1.6) million).
- Interest accrued on the CLNs USD (0.5) million (2017: (0.7) million).

See Note 7 to Consolidated Financial Statements – Finance Costs for further details.

Income Tax Expense

Taxation charge for 2018 of USD (1.3) million (2017: USD 0.03 million credit), and its components are described below.

- Increase in Deferred Tax Asset ("DTA") for the year with tax losses recognised of USD 1.8 million credit (2017: USD (1.3) million).
- Increase in Deferred Tax Liabilities ("DTL") for the year resulting from accelerated tax depreciation USD (3.1) million (2017: credit of USD 0.4 million).
- Unemployment levy ("UL") USD (0.0) million (2017: USD 0.03 million credit).

See Note 8 to Consolidated Financial Statements – Taxation (expense)/credit for further details.

CONSOLIDATED STATEMENT OF CASH FLOWS ANALYSIS

Cash inflow from operating activities

Operating Cash Flow ("OCF") was USD 12.1 million (2017: USD 8.7 million):

- Loss before income tax of USD (4.1) million (2017: USD 25.3 million profit) included non-cash items amounting to USD 16.2 million (2017: USD (16.7) million).
- Changes in working capital of USD (6.8) million (2017: USD 0.9 million inflow), primarily as a result of the increased level of trade receivables at the year end.
- Current income taxation paid USD (0.1) million outflow (2017: nil).

Cash outflow relating to the restructuring

Cash outflow relating to full and final repayment of T&T State Creditors amounted to USD (5.8) million (2017: USD (12.6) million).

Cash outflow from investing activities

Cash outflow from investing activities was USD (12.5) million (2017: USD (3.1) million):

- Expenditure on Property, Plant and Equipment for the year was USD (12.3) million (2017: USD (2.8) million) which mainly included 8 Onshore development wells, 17 recompletions and infrastructure upgrades.
- Expenditure on exploration and evaluation assets USD (0.2 million) (2017: nil).
- Expenditure on new software USD (0.0) million (2017: USD (0.3) million).

Cash inflow from financing activities

Cash inflow from financing activities was USD 11.5 million (2017: USD 10.3 million):

- Issue of shares (net of costs and conversion of CLN) USD 12.4 million (2017: 10.8 million).
- Repayment of CLN USD (0.9) million (2017: nil.).
- Issue of CLN (net of costs) nil (2017: USD 3.0 million).
- Settlement of the compromised Citibank loan nil (2017: USD (3.5) million).

See Note 23 to the Consolidated Financial Statements – Convertible loan notes for further details and see Note 19 to the Consolidated Financial Statements – Issue of shares for further details.

CASH PLUS WORKING CAPITAL SURPLUS

Statement of Financial Position Extract	FY 2018 *USD MM* Unaudited	FY 2017 *USD MM* Audited[1]	FY 2017 *USD MM* Unaudited[2] Mgmt. View
A: Current Assets			
Cash and cash equivalents	10.2	11.8	11.8
Trade and other receivables	13.3	5.2	5.2
Inventories	3.7	3.8	3.8
Total Current Assets	**27.2**	**20.8**	**20.8**
B: Liabilities			
Non-current[3]			
Trade and other payables	-	0.9	1.0
CLN	-	3.0	7.0
Total Non-Current Liabilities	**-**	**3.9**	**8.0**
Current[4]			
Trade and other payables	9.1	10.1	10.2
Taxation payable	-	1.7	1.7
Derivative Financial Instrument	-	0.8	0.8
Total Current Liabilities	9.1	12.6	12.7
Total Liabilities	**9.1**	**16.5**	**20.7**
(A-B): Cash plus working capital surplus	**18.1**	**4.3**	**0.1**

Notes:

1. *States the amortised cost of the CLN and MEEI liabilities as stated in the Financials (see Notes 2, 23 and 25 to the financial statements)*
2. *States the Face Value of the CLN and MEEI liabilities as opposed to amortised cost stated in the unaudited 2018 financials and audited 2017 financials*
3. *Non-Current Liabilities excludes Deferred tax liability & Provision for other liabilities*
4. *Current Liabilities excludes Provision for other liabilities*

Events since the Year End

1. On 2 January 2019 the Company issued awards under its Long-Term Incentive Plan ("LTIP"). The Company awarded the grant of Options over 2,824,000 ordinary shares (representing 0.735% of the Company's issued share capital) under the LTIP.

   The LTIP Awards are subject to the achievement of relative Total Shareholder Return ("TSR") performance targets measured over a three year performance period ending on 1 January 2021. These awards have been made in accordance with the policy announced to the market on 25 August 2017 and have been made to certain individuals in respect of the performance of the Group for the financial year ended 31 December 2017.

2. On 15 January 2019, the Group announced that the effective transition date to the new national oil company, Heritage, was 1 December 2018 and the restructuring process with Petrotrin was ongoing. There have been some delays in the receipt of payments for October and November crude oil revenues from Petrotrin with an amount outstanding of USD 6.7 million at year end.

The Group has to date received USD 4.1 million of these delayed payments, with the remaining USD 2.6 million which is outstanding expected to be collected by the end of H1 2019.

Consolidated Statement of Comprehensive Income
For the year ended 31 December 2018
(Expressed in United States Dollars)

	Note	2018	2017
		$’000	**$’000**
Operating Revenues			
Crude oil sales		62,578	44,957
Other income		15	210
		62,593	45,167
Operating Expenses			
Royalties		(20,390)	(13,755)
Production costs		(17,754)	(14,737)
Depreciation, Depletion & Amortisation (“DD&A”)	11,12	(10,694)	(7,055)
General & Administrative (“G&A”) expenses		(5,960)	(4,326)
Other Expenses		(1,075)	(1,362)
		(55,873)	(41,235)
Operating Profit Before Supplemental Petroleum Taxes (“SPT”) and Property Taxes (“PT”)		**6,720**	**3,932**
SPT		(7,050)	(1,533)
PT		607	(497)
Operating Profit Before Exceptional Items		**277**	**1,902**
Exceptional Items	6	(2,312)	25,718
Operating (Loss)/Profit		**(2,035)**	**27,620**
Net finance costs	7	(2,056)	(2,300)
(Loss)/Profit Before Income Taxation		**(4,091)**	**25,320**
Income Taxation (expense)/credit	8	(1,270)	28
(Loss)/Profit for the year		**(5,361)**	**25,348**
Other Comprehensive Income			
Items that may be subsequently reclassified to profit or loss			
Currency translation		40	76
Total Comprehensive (Loss)/ Income For The Year		**(5,321)**	**25,424**
Earnings per share (expressed in dollars per share)			
Basic	9	(0.02)	0.09
Diluted	9	(0.02)	0.06

Consolidated Statement of Financial Position
at 31 December 2018
(Expressed in United States Dollars)

	Note	2018	2017
ASSETS		**$'000**	**$'000**
Non-current Assets			
Property, plant and equipment	11	53,599	52,450
Intangible assets	12	25,757	25,591
Abandonment fund	13	2,979	1,650
Performance bond	14	253	253
Deferred tax assets	15	5,973	4,179
		88,561	84,123
Current Assets			
Inventories	16	3,738	3,766
Trade and other receivables	17	13,343	5,155
Cash and cash equivalents	18	10,201	11,792
		27,282	20,713
Total Assets		**115,843**	**104,836**
EQUITY AND LIABILITIES			
Capital and Reserves Attributable to Equity Holders			
Share capital	19	97,692	96,676
Share premium	19	139,879	125,362
Other equity		--	590
Share based payment reserve	20	13,290	12,553
Merger reserves	21	75,467	75,467
Reverse acquisition reserve	21	(89,268)	(89,268)
Translation reserve		(1,638)	(1,678)
Accumulated losses		(176,473)	(171,112)
Total Equity		**58,949**	**48,590**
Non-current Liabilities			
Trade and other payables	25	--	881
Convertible Loan Notes ("CLN")	23	--	3,019
Deferred tax liabilities	15	5,598	2,538
Provision for other liabilities	24	41,802	37,151
		47,400	43,589
Current Liabilities			
Trade and other payables	25	9,147	10,092
Provision for other liabilities	24	347	115
Derivative financial instruments	27	--	762
Taxation payable	28	--	1,688
		9,494	12,657
Total Liabilities		**56,894**	**56,246**
Total Equity and Liabilities		**115,843**	**104,836**

Company Statement of Financial Position
at 31 December 2018
(Expressed in United States Dollars)

	Note	2018 $'000	2017 $'000
ASSETS			
Non-current Assets			
Investment in subsidiaries	10	58,489	51,416
Current Assets			
Trade and other receivables	17	84	89
Intercompany	17	6,539	2,447
Cash and cash equivalents	18	4,056	6,024
		10,679	8,560
Total Assets		**69,168**	**59,976**
EQUITY AND LIABILITIES			
Capital and Reserves Attributable to Equity Holders			
Share capital	19	97,692	96,676
Share premium	19	139,879	125,362
Other equity		--	590
Share based payment reserve		2,590	1,853
Merger reserves		56,652	56,652
Accumulated losses		(228,126)	(225,459)
Total Equity		**68,687**	**55,674**
Non - Current Liabilities			
CLN	23	--	3,019
Current Liabilities			
Trade and other payables	25	481	521
Derivative financial instruments	27	--	762
Intercompany	25	--	--
		481	1,283
Total Liabilities		**481**	**4,302**
Total Equity and Liabilities		**69,168**	**59,976**

Consolidated Statement of Changes in Equity
for the year ended 31 December 2018
(Expressed in United States Dollars)

	Share Capital	Share Premium	Other Equity	Share Warrants	Share Based Payment Reserve	Reverse Acquisition Reserve	Merger Reserves	Translation Reserve	Accumulated Losses	Total Equity
Year ended 31 December 2017	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**
At 1 January 2017	94,800	116,395	--	71	12,244	(89,268)	75,467	(1,997)	(196,460)	11,252
Other equity net of transaction cost	--	--	590	--	--	--	--	--	--	590
Issue of shares	1,876	8,967	--	--	--	--	--	--	--	10,843
Share based payment expense	--	--	--	--	309	--	--	--	--	309
Share warrants expired	--	--	--	(71)	--	--	--	--	--	(71)
Translation difference	--	--	--	--	--	--	--	243	--	243
Total comprehensive income for the period	--	--	--	--	--	--	--	76	25,348	25,424
At 31 December 2017	**96,676**	**125,362**	**590**	**--**	**12,553**	**(89,268)**	**75,467**	**(1,678)**	**(171,112)**	**48,590**
Year ended 31 December 2018										
At 1 January 2018	**96,676**	**125,362**	**590**	**--**	**12,553**	**(89,268)**	**75,467**	**(1,678)**	**(171,112)**	**48,590**
Issue of shares	1,016	18,984	--	--	--	--	--	--	--	20,000
Cost of raising equity	--	(1,202)	--	--	--	--	--	--	--	(1,202)
CLN - discount	--	(3,265)	--	--	--	--	--	--	--	(3,265)
CLN – conversion	--	--	(590)	--	--	--	--	--	--	(590)
Share based payment expense (Note 20)	--	--	--	--	737	--	--	--	--	737
Total comprehensive expense for the year	--	--	--	--	--	--	--	40	(5,361)	(5,321)
At 31 December 2018	**97,692**	**139,879**	**--**	**--**	**13,290**	**(89,268)**	**75,467**	**(1,638)**	**(176,473)**	**58,949**

Company Statement of Changes in Equity
for the year 31 December 2018
(Expressed in United States Dollars)

	Share Capital	Share Premium	Other Equity	Share Based Payment Reserve	Merger Reserves	Accumulated Losses	Total Equity
	$'000	$'000	$'000	$'000	$'000	$'000	$'000
Year ended 31 December 2017							
At 1 January 2017	94,800	116,395	--	1,544	56,652	(222,235)	47,156
Other equity net of transaction costs	--	--	590	--	--	--	590
Issue of ordinary shares	1,876	8,967	--	--	--	--	10,843
Share based payment expense	--	--	--	309	--	--	309
Total comprehensive expense for the year	--	--	--	--	--	(3,224)	(3,224)
At 31 December 2017	**96,676**	**125,362**	**590**	**1,853**	**56,652**	**(225,459)**	**55,674**
Year ended 31 December 2018							
At 1 January 2018	96,676	125,362	590	1,853	56,652	(225,459)	55,674
Issue of ordinary shares	1,016	18,984	--	--	--	--	20,000
Cost of raising equity	--	(1,202)	--	--	--	--	(1,202)
CLN - discount	--	(3,265)	--	--	--	--	(3,265)
CLN – conversion	--	--	(590)	--	--	--	(590)
Share based payment expense	--	--	--	737	--	--	737
Total comprehensive expense for the year	--	--	--	--	--	(2,667)	(2,667)
At 31 December 2018	**97,692**	**139,879**	**--**	**2,590**	**56,652**	**(228,126)**	**68,687**

Consolidated Statement of Cash Flows
for the year ended 31 December 2018
(Expressed in United States Dollars)

	Note	2018 $'000	2017 $'000
Operating Activities			
(Loss)/Profit before taxation		(4,091)	25,320
Adjustments for:			
Translation difference		330	(663)
Finance cost – loans and interest	7	499	579
Share based payment expense	20	737	235
Finance cost – decommissioning provision	24	1,557	1,643
DD&A	11	10,694	7,055
Loss on disposal of assets	11	(6)	--
Impairment of property, plant and equipment	11	2,561	--
Impairment of receivables		--	348
Impairment of inventory		--	264
Gain on extinguishment of financial liabilities		--	(210)
Unsecured creditors' claims		(192)	--
Fair value zero cost collar		--	762
Compromised creditor balances		--	(26,672)
		12,089	8,661
Changes In Working Capital			
Inventories	16	28	(243)
Trade and other receivables	17	(9,513)	(887)
Trade and other payables	25	2,731	2,023
Income Taxation paid		(128)	--
Net Cash Inflow From Operating Activities		5,207	9,554
Restructuring related payments			
Unsecured creditors		--	(3,857)
T&T State creditors (BIR and MEEI)		(5,835)	(8,775)
		(5,835)	(12,632)
Investing Activities			
Purchase of exploration and evaluation assets	12	(170)	--
Purchase of computer software	12	(26)	(250)
Purchase of property, plant and equipment	11	(12,264)	(2,868)
Net Cash Outflow From Investing Activities		(12,460)	(3,118)
Financing Activities			
Issue of shares (net of costs)	19	12,361	10,843
Repayment of CLN	23	(770)	--
Finance Cost- CLN Interest	23	(94)	
Issue of CLN (net of costs)	23	--	3,030
Repayment of borrowings		--	(3,500)
Net Cash Inflow From Financing Activities		11,497	10,373
(Decrease)/Increase in Cash and Cash Equivalents		(1,591)	4,177
Cash And Cash Equivalents			
At beginning of year		11,792	7,615
(Decrease)/increase in cash and cash equivalents		(1,591)	4,177
At end of year	18	10,201	11,792

Company Statement of Cash Flows
for the year ended 31 December 2018
(Expressed in United States Dollars)

	Note	2018 $'000	2017 $'000
Operating Activities			
Loss before taxation		(2,667)	(3,161)
Adjustments for:			
Translation differences		10	69
Finance income		(215)	(270)
Finance cost		418	579
Share based payment expense		123	91
Fair value zero cost collar		--	762
Compromised creditor balances		--	446
		(2,331)	(1,484)
Changes In Working Capital			
Trade and other receivables		(4,088)	134
Trade and other payables		(802)	(553)
		(4,890)	(419)
Taxation Paid		--	--
Net Cash Outflow from Operating Activities		(7,221)	(1,903)
Financing Activities			
Finance income		215	270
Finance cost		(94)	(579)
Capital contributed to subsidiary	10	(6,459)	(6,395)
Issue of shares (net of costs)	19	12,361	10,843
Issue of CLN (net of costs)	23	--	3,030
Repayment of CLN		(770)	--
Net Cash Inflow from Financing Activities		5,253	7,169
(Decrease)/Increase In Cash And Cash Equivalents		(1,968)	5,266
Cash And Cash Equivalents			
At beginning of year		6,024	758
(Decrease)/Increase in cash and cash equivalents		(1,968)	5,266
At end of year	18	4,056	6,024

1 Background and Accounting Policies

The principal accounting policies applied in the preparation of this consolidated financial information are set out below. These policies have been consistently applied to all the years presented, unless otherwise stated.

Background

Trinity Exploration & Production plc ("Trinity" or "the Company") previously Bayfield Energy Holdings plc ("Bayfield") was incorporated and registered in England and Wales on 21 February, 2011 and traded on the Alternative Investment Market ("AIM"), a market operated by London Stock Exchange plc. On 14 February, 2013, Bayfield was acquired by Trinity Exploration & Production (UK) Limited ("TEPUKL"), a Company incorporated in Scotland, through a reverse acquisition. Bayfield changed its name to Trinity Exploration & Production plc and the enlarged group was re-admitted to trading on AIM. Trinity and its subsidiaries (together "the Group") are involved in the exploration, development and production of oil reserves in Trinidad & Tobago ("T&T").

Basis of Preparation

This consolidated financial information has been prepared on a going concern basis, in accordance with International Financial Reporting Standards ("IFRS") as adopted by the European Union ("EU"), IFRS Interpretations Committee ("IFRS IC") interpretations as adopted by the EU and those parts of the Companies Act 2006 as applicable to companies reporting under IFRS. This consolidated financial information has been prepared under the historical cost convention, with the exception of certain financial assets, financial liabilities (including derivative instruments and the CLN) and classes of property, plant and equipment which are measured at fair value.

The preparation of the consolidated financial information in conformity with IFRS requires the use of certain critical accounting estimates. It also requires management to exercise its judgement in the process of applying the Group's accounting policies. The areas involving a higher degree of judgement or complexity, or areas where assumptions and estimates are significant to the consolidated financial information are disclosed in Note 3: Critical Accounting Estimates and Assumptions.

The Company has taken advantage of the exemption in Section 408 of the Companies Act 2006 not to present its own income statement or statement of comprehensive income. The loss for the Company for the year was $2.7 million (2017: $3.2 million loss).

Going Concern

In making their going concern assessment, the Board of Directors (the "Board") have considered the Group's budget and cash flow forecasts. The Group's main objective in 2018 was to grow production, through a fully funded onshore drilling programme and a low cost work programme of Recompletions ("RCPs"), Workovers ("WOs"), reactivations and swabbing.

In July 2018, gross proceeds of $20.0 million were raised through the Fundraising. The Fundraising allowed the Group to repay all outstanding debt to its Board of Inland Revenue of T&T ("BIR") and Ministry of Energy and Energy Industries of T&T ("MEEI") (together the "T&T State Creditors"). Subsequent to this repayment, on 15 August 2018 Trinity settled the remaining balance of the redeemable CLN plus accrued interest. Through the settlement of all outstanding debts, the Group improved on its prior year net current asset position. At 31 December 2018, the Group held net current assets of $17.8 million (2017: $8.1 million).

The Group meets its day-to-day working capital requirements through revenue generation and positive operating cash flows. The Group's forecast and projections, taking account of reasonable possible changes in oil price and sales volume, show that the Group will be able to operate within the level of its current cash resources. Should there be a decline in the oil price, the Board believe there are a number of actions within their control that can be effected. These include deferral of capital expenditure and further reducing operating costs to manageable levels. For these reasons, the Board have a reasonable expectation that the Group has adequate resources to continue operational existence for the foreseeable future.

The Board has carefully considered and formed a reasonable judgement that, at the time of approving these financial statements, the Group and Company are in a stable position. The Group is able to pay its debts as they fall due for a period of at least 12 months post approval of the financial statements and is poised for continued growth. For this reason, the Board continues to adopt the going concern basis when preparing these financial statements.

New and amended standards adopted by the Group:
The Group has applied the following standards and amendments for the first time for annual reporting period commencing 1 January 2018:

IFRS 9 Financial Instruments	The standard addresses the classification, measurement and de-recognition of financial assets and financial liabilities, introduces new rules for hedge accounting and a new impairment model for financial assets. The Group assessed the impact with the introduction of the new guidance on the classification and measurement of these financial assets. There is no material impact in accounting for financial liabilities that are designated at fair value through profit or loss.	Periods beginning on / after 1 January 2018
IFRS 15 Revenue from Contracts with Customers	The new standard for revenue replaces IAS 18 and IAS 11. IFRS 15 specifies how and when an IFRS reporter will recognise revenue as well as requiring such entities to provide users of the financial statements with more informative, relevant disclosures. The Group reviewed its sales contracts with customers and determined that IFRS 15 did not have a material impact on its revenue recognition and, accordingly, no material impact on the Consolidated Financial Statements. Trinity adopted this standard using the modified retrospective approach, whereby the cumulative effect of initial adoption of the standard is recognised as an adjustment to retained earnings. There was no effect on the Group's retained earnings or prior period amounts as a result of adopting this standard.	Periods beginning on / after 1 January 2018

IFRS 2 Share-based payment IFRS	The amendments to the classification and measurement of share-based payment transactions. The amendments affect three distinct areas. 1) Classification of share-based payments that have a net settlement feature within the framework of an equity-settled plan. 2) Accounting for modifications that change the classification of payments from cash-settled to equity-settled. 3) The effects of vesting/non-vesting conditions on cash-settled share-based payments.	Periods beginning on / after 1 January 2018

New and amended standards not yet adopted by the Group:
Certain new accounting standards and interpretations have been published that are not mandatory for 31 December 2018 reporting periods and have not been early adopted by the Group. The Group's assessment of the impact of these new standards and interpretations is set out below.

IFRS 16 Leases	This is a new accounting standard which will result in almost all leases being recognised on the balance sheet, as the distinction between operating and finance leases is removed. Under the new standard, an asset (the right to use the leased item) and a financial liability to pay rentals are recognised. The only exceptions are short-term and low-value leases. The accounting for lessors will not significantly change. Management has assessed the estimated impact of the adoption of IFRS 16 on existing leases and have determined that in the first year of adoption there would be a $0.5 million reclassification of operating cost to depreciation and interest. The impact to the balance sheet would be the recognition of a right of use asset of $0.5 million and a lease liability of $0.5 million. The Group will apply the standard from its mandatory adoption date of 1 January 2019. The Group intends to apply the simplified transition approach and will not restate comparative amounts for the year prior to first adoption. Right-of-use assets for property leases will be measured on transition as if the new rules had always been applied. All other right-of-use assets will be measured at the amount of the lease liability on adoption (adjusted for any prepaid or accrued lease expenses).	Periods beginning on / after 1 January 2019

Basis of consolidation

The consolidated financial information incorporates the financial information of the Company and entities controlled by the Company (its subsidiaries) made up to 31 December each year. Control is achieved where the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities.

The results of subsidiaries acquired or disposed of during the year are included in the consolidated statement of comprehensive income from the effective date of acquisition and up to the effective date of disposal, as appropriate.

The acquisition method of accounting is used to account for the acquisition of subsidiaries by the Group. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date, irrespective of the extent of any non-controlling interest. The excess of the cost of acquisition over the fair value of the Group's share of the identifiable net assets acquired is recorded as goodwill. If the cost of acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognised directly in the statement of comprehensive income. Costs related to an acquisition are expensed as incurred.

Uniform accounting policies have been adopted across the Group. All intra-Group transactions, balances, income and expenses are eliminated on consolidation.

Share-based payments

The Group operates a number of equity-settled, share-based compensation plans comprised of share options and Long Term Incentive Plans ("LTIPs") as consideration for services rendered by the Group's employees. The fair value of the services received in exchange for the grant of share-based payments is recognised as an expense. The total amount to be expensed is determined by reference to the fair value of the options or LTIP awards granted:
- including any market performance conditions (for example, an entity's share price);
- excluding the impact of any service and non-market performance vesting conditions; and
- including the impact of any non-vesting conditions.

Non-market performance and service conditions are included in assumptions about the number of share-based payments that are expected to vest. The total expense is recognised over the vesting period, which is the period over which all of the specified vesting conditions are to be satisfied.

At the end of each reporting period, the Group revises its estimates of the number of options or LTIP awards that are expected to vest based on the non-market vesting conditions. It recognises the impact of the revision to original estimates, if any, in the statement of comprehensive income, with a corresponding adjustment to equity. When the options are exercised, the Group issues new shares. The proceeds received net of any directly attributable transaction costs are credited to share capital (nominal value) and share premium.

The grant by the Company of options and LTIPs over its equity instruments to the employees of subsidiary undertakings in the Group is treated as a capital contribution. The fair value of employee services received, measured by reference to the grant date fair value, is recognised over the vesting period as an increase to investment in subsidiary undertakings, with a corresponding credit to equity.

Foreign currency translation

(a) Functional and presentation currency

Company: The functional and presentation currency of the Company is United States Dollars ("USD" or "$").

Group: The functional currency of the Group operating entities is Trinidad & Tobago Dollars ("TTD") as this is the currency of the primary economic environment in which the entities operate. The presentation currency is USD which better reflects the Group's business activities and improves the ability of users of the financial statements to compare financial results with others in the International Oil and Gas industry. The Consolidated Statement of Financial Position is translated at the closing rate and Consolidated Statement of Comprehensive Income is translated at the average rate from both USD and Great British Pound ("GBP" or "£") currencies. The following exchange rates have been used in the preparation of these financial statements:

	2018		**2017**	
	$	£	$	£
Average rate TTD= $/£	6.762	9.107	6.751	8.831
Closing rate TTD= $/£	6.781	8.644	6.771	9.207

(b) *Transactions and balances*

Foreign currency transactions are translated into the functional currency using the exchange rates at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation of monetary assets and liabilities denominated in foreign currencies at year end exchange rates are generally recognised in profit or loss. They are deferred in equity if they relate to qualifying cash flow hedges and qualifying net investment hedges or are attributable to part of the net investment in a foreign operation.

Foreign exchange gains and losses that relate to borrowings are presented in the statement of profit or loss, within finance costs. All other foreign exchange gains and losses are presented in the statement of profit or loss on a net basis within G&A expenses.

Non-monetary items that are measured at fair value in a foreign currency are translated using the exchange rates at the date when the fair value was determined. Translation differences on assets and liabilities carried at fair value are reported as part of the fair value gain or loss. For example, translation differences on non-monetary assets and liabilities such as equities held at fair value through profit or loss are recognised in profit or loss as part of the fair value gain or loss and translation differences on non-monetary assets such as equities classified as available-for-sale financial assets are recognised in other comprehensive income.

(c) *Group companies*

The results and financial position of foreign operations (none of which has the currency of a hyperinflationary economy) that have a functional currency different from the presentation currency are translated into the presentation currency as follows:

- assets and liabilities for each balance sheet presented are translated at the closing rate at the date of that balance sheet
- income and expenses for each statement of profit or loss and statement of comprehensive income are translated at average exchange rates (unless this is not a reasonable approximation of the cumulative effect of the rates prevailing on the transaction dates, in which case income and expenses are translated at the dates of the transactions), and
- all resulting exchange differences are recognised in other comprehensive income.

On consolidation, exchange differences arising from the translation of any net investment in foreign entities, and of borrowings and other financial instruments designated as hedges of such investments, are recognised in other comprehensive income. When a foreign operation is sold or any borrowings forming part of the net investment are repaid, the associated exchange differences are reclassified to profit or loss, as part of the gain or loss on sale.

(d) Translation differences

Differences arising from retranslation of the financial statements at the year-end are recognised in the Translation reserve through "Other comprehensive income".

Intangible assets

(a) Exploration and evaluation assets

i) Capitalisation

Exploration and Evaluation assets are initially classified as intangible assets. Such costs include those directly associated with an exploration area. Upon discovery of commercial reserves capitalisation is recognised within Property, Plant and Equipment.

Oil and natural gas exploration and evaluation expenditures are accounted for using the successful efforts method of accounting. Under this method, costs are accumulated on a prospect-by-prospect basis and capitalised upon discovery of commercially viable mineral reserves. If the commercial viability is not achieved or achievable, such costs are charged to expense.

Costs incurred in the exploration and evaluation of assets includes*:*

- *Licence and property acquisition costs*
  Exploration and property leasehold acquisition costs are capitalised within exploration and evaluation assets.
- *Exploration and evaluation expenditure*
  Costs directly associated with an exploration well are capitalised until the determination of reserves is evaluated. Such costs include topographical, geological, geochemical, and geophysical studies, exploratory drilling costs, trenching, sampling and activities in relation to evaluating the technical feasibility and commercial viability of extracting mineral resources. Capitalisation is made within property, plant and equipment or intangible assets according to its nature however a majority of such expenditure is capitalised as an intangible asset. If commercial reserves are found, the costs continue to be carried as an asset. If commercial reserves are not found, exploration and evaluation expenditures are written off as a dry hole when that determination is made.

  Once commercial reserves are found, exploration and evaluation assets are tested for impairment and transferred to development tangible and intangible assets as applicable. No depreciation and/or amortisation are charged during the exploration and evaluation phase.

ii) Impairment

Exploration and evaluation assets are tested for impairment (in accordance with the criteria set out in IFRS 6: Exploration for and Evaluation of Mineral Resources) whenever facts and circumstances indicate impairment. An impairment loss is recognised for the amount by which the exploration and evaluation assets' carrying amount exceed their recoverable amount. The recoverable amount is the higher of the exploration and evaluations assets' fair value less costs of disposal and their Value In Use ("VIU"). For the purposes of assessing impairment, the exploration and evaluation assets subject to testing are grouped with existing Cash Generating Units ("CGU") of related production fields located in the same geographical region. The geographical region is the same as that used for reserves reporting purposes.

The following indicators are evaluated to determine whether these assets should be tested for impairment:

- The period for which the Group has the right to explore in the specific area has lapsed.
- Whether substantive expenditure on further exploration and evaluation in the specific area is budgeted or planned.
- Whether exploration and evaluation in the specific area have not led to the discovery of commercially viable quantities and the Company has decided to discontinue such activities in the specific area.
- Whether sufficient data exists to indicate that, although a development in the specific area is likely to proceed, the carrying amount of the exploration and evaluation asset is unlikely to be recovered in full from successful development or by sale.

(b) Goodwill

Goodwill is initially measured at cost, being the excess of the aggregate of the consideration transferred and the amount recognised for non-controlling interest over the net identifiable assets acquired and liabilities assumed. If this consideration is lower than the fair value of the net assets of the subsidiary acquired, the difference is recognised in profit or loss.
After initial recognition, goodwill is measured at cost less any accumulated impairment losses. For the purpose of impairment testing, goodwill acquired in a business combination is, from the acquisition date, allocated to each of the Company's cash-generating units that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquiree are assigned to those units.

(c) Computer software

Computer software is initially recognised at cost, once it is purchased. Internally generated software is capitalised once it is proven technological feasibility, probable future benefits, intent and ability to use the software, resources to complete the software, and ability to measure cost. It is amortised over its useful life, based on pattern of benefits (straight-line is the default).

Property, plant and equipment

(a) Oil and gas assets

i) Development and Producing Assets – Capitalisation

Development expenditures are costs incurred to obtain access to proven reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. These costs include transfers from exploration and evaluations subsequent to finding commercially viable reserves, development drilling and new reserve type, infrastructure costs and development Geological and Geophysical ("G&G") costs. Acquisitions of oil and gas properties are accounted for under the acquisition method where the transaction meets the definition of a business combination.

Transactions involving the purchases of an individual field interest, or a group of field interests, that do not meet the definition of a business (therefore do not apply business combination accounting) are treated as asset purchases, irrespective of whether the specific transactions involve the transfer of the field interests directly, or the transfer of an incorporated entity. Accordingly, the consideration is allocated to the assets and liabilities purchased on a relative fair value basis.

Proceeds on disposal are applied to the carrying amount of the specific asset or development and production assets disposed of. Any excess is recorded as a gain on disposal in the statement of comprehensive income and any shortfall between the proceeds and the carrying amount is recorded as a loss on disposal in the statement of comprehensive income.

Development expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development commercially proven wells is capitalised according to its nature. When development is completed on a specific field it is transferred to Production Assets. No depreciation and/or amortisation are charged during the development phase.

Expenditure on G&G surveys used to locate and identify properties with the potential to produce commercial quantities of oil and gas as well as to determine the optimal location for development wells are capitalised.

ii) Development and Producing Assets – Impairment

An impairment test is performed whenever events and circumstances arising during the development or production phase indicate that the carrying value of a development or production asset may exceed its recoverable amount. Impairment triggers include but are not limited to, declining long term market prices for oil and gas, significant downward reserve revisions, increased regulations or fiscal changes, deteriorating local conditions such that it become unsafe to continue operations) and obsolescence.

The carrying value is compared against the expected recoverable amount. The recoverable amount is the higher of an asset's fair value less costs of disposal and the VIU. For the purposes of assessing impairment, assets are grouped at the lowest levels (its cash generating unit) for which there are separately identifiable cash flows. The cash generating unit applied for impairment test purposes is generally the field. These fields are the same as that used for reserves reporting purposes.

iii) Producing Assets – Depreciation, Depletion & Amortisation("DD&A")

The provision for DD&A of developed and producing oil and gas assets are calculated using the unit-of-production method. Oil and gas assets are depreciated generally on a field-by-field basis using the unit-of-production method which is the ratio of oil and gas production in the period to the estimated quantities of commercial reserves at the end of the period plus the production in the period. Costs used in the unit of production calculation comprise the net book value of capitalised costs plus the estimated future development costs. Changes in the estimates of commercial reserves or future development costs are dealt with prospectively.

iv) Decommissioning asset

Provision for decommissioning is recognised in accordance with the contractual obligations at the commencement of oil and gas production. The amount recognised is the net present value of the estimated cost of decommissioning at the end of the economic producing lives of the wells and the end of the useful lives of refinery and storage units. Such costs include removal of equipment and restoration of land or seabed. The unwinding of the discount on the provision is included in the statement of comprehensive income within finance costs.

A corresponding asset is also created at an amount equal to the provision. This is subsequently depleted as part of the capital costs of the production assets. Any change in the present value of the estimated expenditure or discount rates are reflected as an adjustment to the provision and the asset and dealt with prospectively.

(b) Non-oil and gas assets

All property, plant and equipment are recorded at historical cost less accumulated depreciation and any impairment losses. Historical cost includes the original purchase price of the asset and expenditure that is directly attributable to bringing the asset to its working condition for its intended use. Subsequent costs are included in the asset's carrying amount or recognised as a separate asset, as appropriate, only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be measured reliably.

The provision for depreciation with respect to operations other than oil and gas producing activities is computed using the straight-line method based on estimated useful lives as follows:

Leasehold and buildings	20 years
Plant and equipment	4 years
Other	4 years

The assets' residual values and useful lives are reviewed and adjusted if appropriate at each statement of financial position date. An asset's carrying amount is written down immediately to its recoverable amount if the asset's carrying amount is greater than its estimated recoverable amount.

Gains and losses on disposals are determined by comparing proceeds with carrying amounts and are included in the statement of comprehensive income.

Repairs and maintenance are charged to the statement of comprehensive income during the financial period in which they are incurred. The cost of major renovations is included in the carrying amount of the asset when it is probable that future economic benefits in excess of the originally assessed standard of performance of the existing assets will flow to the Group. Major renovations such as leasehold improvements are depreciated over the remaining useful life of the related asset.

Impairment of non-financial assets

At each reporting date, assets that have an indefinite useful life, for example, goodwill, are not subject to amortisation and are tested for impairment. Assets that are subject to amortisation are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is recognised for the amount by which the asset's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of an asset's fair value less costs of disposal and value in use. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows (cash generating units). Non-financial assets other than goodwill that suffered impairment are reviewed for possible reversal of the impairment at each reporting date.

Inventories

Crude oil is stated at the lower of cost and net realisable value. Cost is determined by the average cost method. Net realisable value is the estimated selling price in the ordinary course of business, less applicable variable selling expenses.

Materials and supplies used mainly in drilling wells, recompletions and workovers are stated at lower of cost and net realisable value. Cost is determined using the average cost method.

Cash and cash equivalents

For the purpose of presentation in the statement of cash flows, cash and cash equivalents includes cash on hand, deposits held at call with financial institutions, other short-term, highly liquid investments with original maturities of three months or less that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value, and bank overdrafts. Bank overdrafts are shown within borrowings in current liabilities in the balance sheet.

Trade receivables

Trade receivables are amounts due from customers for crude oil sold in the ordinary course of business. They are generally due for settlement within 30 days and therefore are all classified as current. Trade receivables are recognised initially at the amount of consideration that is unconditional unless they contain significant financing components, when they are recognised at fair value.

The Group applies the simplified approach to determine impairment of trade receivables. The simplified approach requires expected lifetime losses to be recognised from initial recognition of the receivables. This involves determining expected loss rates using a provision matrix that is based on the Group's historical default rates observed over the expected life of the receivable and adjusted forward-looking estimates. This is then applied to the gross carrying amount of the receivable to arrive at the loss allowance for the period.

Trade payables

Trade payables are recognised initially at fair value and subsequently measured at amortised cost using the effective interest method.

Impairment of financial assets

Financial assets recognition of impairment provisions under IFRS 9 is based on the expected credit losses ("ECL") model. The ECL model is applicable to financial assets classified at amortised cost and contract assets under IFRS 15: Revenue from Contracts with Customers. The measurement of ECL reflects an unbiased and probability weighted amount that is available without undue cost or effort at the reporting date, about past events, current conditions and forecasts of future economic conditions. The Group applied the simplified approach to determine impairment of its trade and other receivables. The simplified approach requires expected lifetime losses to be recognised from initial recognition of the receivables. This involves determining the expected loss rates using a provision matrix that is based on the Group's historical default rates observed over the expected life of the receivables and adjusted for forward looking estimates. This is then applied to the gross carrying amount of the receivables to arrive at the loss allowance for the period.

Income tax

The income tax expense or credit for the period is the tax payable on the current period's taxable income based on the applicable income tax rate for each jurisdiction adjusted by changes in deferred tax assets and liabilities attributable to temporary differences and to unused tax losses.

The current income tax charge is calculated on the basis of the tax laws enacted or substantively enacted at the end of the reporting period in the countries where the Company's subsidiaries and associates operate and generate taxable income. Management periodically evaluates positions taken in tax returns with respect to situations in which applicable tax regulation is subject to interpretation. It establishes provisions where appropriate on the basis of amounts expected to be paid to the tax authorities.

Deferred income tax is provided in full, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the consolidated financial statements. However, deferred tax liabilities are not recognised if they arise from the initial recognition of goodwill. Deferred income tax is also 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/loss. Deferred income tax is determined using tax rates (and laws) that have been enacted or substantially enacted by the end of the reporting period and are expected to apply when the related deferred income tax asset is realised or the deferred income tax liability is settled.

The deferred tax liability in relation to investment property that is measured at fair value is determined assuming the property will be recovered entirely through sale.

Deferred tax assets are recognised only if it is probable that future taxable amounts will be available to utilise those temporary differences and losses.

Deferred tax liabilities and assets are not recognised for temporary differences between the carrying amount and tax bases of investments in foreign operations where the Company is able to control the timing of the reversal of the temporary differences and it is probable that the differences will not reverse in the foreseeable future.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to offset current tax assets and liabilities and when the deferred tax balances relate to the same taxation authority. Current tax assets and tax liabilities are offset where the entity has a legally enforceable right to offset and intends either to settle on a net basis, or to realise the asset and settle the liability simultaneously.

Current and deferred tax is recognised in profit or loss, except to the extent that it relates to items recognised in other comprehensive income or directly in equity. In this case, the tax is also recognised in other comprehensive income or directly in equity, respectively.

Property Taxes ("PT")

PT are recognised initially at fair value and subsequently measured at amortised cost using the effective interest method. Assessments are based on the Annual Rental Value ("ARV") of property. The Annual Taxable Value ("ATV") is the ARV subject to deductions and allowances in respect of voids and loss of rent multiplied by the respective PT rate. The PT rate applicable to the Group are industrial with building rates at 6% and industrial without building 3%.

Revenue recognition

IFRS 15 Revenue from Contracts with Customers replaces IAS 18 and IAS 11 with effect from accounting periods commencing 1 January 2018. The new standard requires that revenue is recognised by performance obligation, as or when each performance obligation is satisfied, and that variable elements of pricing are recognised, to the extent that is it not highly probable they will be reversed.

The Group has evaluated its customer contract with the Petroleum Company of Trinidad & Tobago Limited ("Petrotrin") and, from 1 December 2018, Heritage Petroleum Company Limited ("Heritage") to identify performance obligations, timing of revenue recognition and treatment of variable elements of pricing. Sales revenue represents the sales value of the Group's oil sold in the year.

Oil revenue is recognised when title of the crude has passed to the buyer by means of a sales ticket document. Typically, payment for the sale of the oil is received by the end of the month following the month in which the sale is recognised.

Prices are determined by Petrotrin/Heritage, with agreed contractual adjustments based on oil quality. Revenue is measured at the fair value of the consideration received or receivable, and represents amounts receivable for oil and gas products in the normal course of business.

Borrowings

Borrowings are recognised initially at fair value net of transaction costs incurred. Borrowings are subsequently stated at amortised cost; any differences between proceeds (net of transaction costs) and the redemption value is recognised in the statement of comprehensive income over the period of the borrowings using the effective interest method.

Borrowings are classified as current liabilities unless the Group has an unconditional right to defer settlement of the liability for at least 12 months after the statement of financial position date.

General and specific borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use or sale, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use or sale.

All other borrowing costs are recognised in comprehensive income in the period in which they are incurred.

Compound Financial Instruments

Compound financial instruments issued by the Group comprised the CLN that could, in certain circumstances, have been converted to share capital at the option of the holder, and the number of shares to be issued did not vary with changes in their fair value. The liability component of a compound financial instrument is recognised initially at the fair value of a similar liability that does not have an equity conversion option. The equity component is recognised initially as the difference between the fair value of the compound financial instrument as a whole and the fair value of the liability component. Any directly attributable transaction costs are allocated to the liability and equity components in proportion to their initial carrying amounts. Subsequent to initial recognition, the liability component of a compound financial instrument is measured at amortised cost using the effective interest rate method. The equity component of a compound financial instrument is not re-measured subsequent to initial recognition except on conversion or expiry.

Provisions

Provisions are recognised when the Group has a present legal or constructive obligation as a result of past events, where it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount of the obligation can be made. Provisions are not recognised for future operating losses.

Where there are a number of similar obligations, the likelihood that an outflow will be required in settlement is determined by considering the class of obligations as a whole. A provision is recognised even if the likelihood of an outflow with respect to any one item included in the same class of obligations may be small.

Provisions are measured at the present value of the expenditures expected to be required to settle the obligation using a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the obligation. The increase in the provision due to passage of time is recognised as a finance cost.

Leases

Leases in which a significant portion of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Payments made under operating leases (net of any incentives received from the lessor) are charged to the income statement on a straight-line basis over the period of the Lease.

Share capital

Ordinary shares are classified as equity. The nominal value of any shares issued is recognised in share capital with the excess above the nominal amount paid being shown within share premium. Incremental costs directly attributable to the issue of new ordinary shares are shown in equity. Where, on issuing shares, share premium has been recognised, the expenses of issuing those shares and any commission paid on the issue of those shares have been written off against the share premium account.

Derivatives and hedging activities

Derivatives are initially recognised at fair value on the date a derivative contract is entered into and are subsequently re-measured to their fair value at the end of each reporting period. The accounting for subsequent changes in fair value depends on whether the derivative is designated as a hedging instrument, and if so, the nature of the item being hedged. The Group has not applied hedge accounting and all derivatives are measured at fair value through profit and loss.

Financial assets at fair value through profit or loss are financial assets held for trading. A financial asset is classified in this category if acquired principally for the purpose of selling in the short term. Derivatives are also categorised as held for trading unless they are designated as hedges. Assets in this category are classified as current assets if expected to be settled within 12 months, otherwise they are classified as non-current. Financial assets are derecognised when the rights to the cash flows expire, risks and rewards are transferred or control of the asset is transferred.

A financial liability is removed from the balance sheet only when it is extinguished – that is, when the obligation specified in the contract is discharged or cancelled – or expires.

Operating segment information

The steering committee is the Group's chief operating decision-maker. Management has determined the operating segments which are Onshore, West Coast and East Coast reported in a manner consistent with the internal reporting provided to the chief operating decision maker. The chief operating decision maker is responsible for making strategic decisions inclusive of; allocating resources and assessing performance of the operating segments. The chief operating decision maker has been identified as the steering committee of Management which comprises; the Executive Chairman, Country Manager, Chief Operations Officer and Chief Financial Officer, that makes strategic decisions in accordance with Board policy.

Investments

Investments are shown at cost less provision for any impairment in value. The Company performs impairment reviews in respect of investments whenever events or changes in circumstances indicate that the carrying amount of the investment may not be recoverable. An impairment loss is recognised when the higher of the investment's net realisable value and fair value less cost of disposal is less than the carrying amount.

Exceptional Items

Exceptional items are disclosed separately in the financial statements where it is necessary to do so to provide further understanding of the financial performance of the Group. They are material items of income or expense that have been shown separately due to the non-recurring nature and the significance of their nature or amount.

2 Financial Risk Management

Financial risk factors

The Group's activities expose it to a variety of financial risks. The Group's overall risk management program seeks to minimise potential adverse effects on the Group's financial performance.

Risk management is carried out by management. Management identifies and evaluates financial risks.

(a) **Market risk**

(i) Foreign exchange risk

The Group is exposed to foreign exchange risk primarily with respect to the United States dollar. Foreign exchange risk arises from future commercial transactions and recognised assets and liabilities which are denominated in a currency that is not the entity's functional currency.

At 31 December 2018, if the functional currency of the main operating subsidiary had weakened/ strengthened by 10% against the US dollar with all other variables held constant, post-tax profit/(loss) for the year would have been $2.9 million (2017: $2.1 million) lower/higher, mainly as a result of foreign exchange gain/losses on translation of US dollar-denominated borrowings and sales.

(ii) Price risk

The Group is exposed to commodity price risk regarding its sales of crude oil which is an internationally traded commodity.

At 31 December 2018, if commodity prices had been 20% higher/lower with all other variables held constant, post-tax profit/(loss) for the year would have been \$12.5 million (2017: \$8.7 million) lower/higher. The sensitivity doesn't take into consideration the impact of the derivative instruments in place over commodity prices.

(iii) Cash flow and fair value interest rate risk

The Group's main interest rate risk arises from borrowings which expose the Group to cash flow interest rate risk. The Group manages risk by limiting the exposure to floating interest rates and maintain a balance between floating and fixed contract rates.

At 31 December 2018, there were no loan commitments to attract interest rates on foreign currency-denominated borrowings, (2017: nil).

(b) **Credit risk**

Credit risk arises from cash and cash equivalents, deposits with banks and financial institutions, as well as credit exposures to customers, including outstanding receivables. For banks and financial institutions, management determines the placement of funds based on its judgement and experience to minimise risk.

All sales are made to a state-owned entity – Petrotrin/Heritage.

The Group applies the IFRS 9 simplified model for measuring ECL which uses a lifetime expected loss allowance and are measured on the days past due criterion. Having reviewed past payments combined with the credit profile of its existing trade debtors in order to assess the potential for impairment, the Company has concluded that this is insignificant as there has been no history of default or disputes arising on invoiced amounts since inception and as such the credit loss percentage is assumed to be almost zero. No provision for doubtful accounts against these sales has been recorded as at 31 December 2018 and 31 December 2017.

(c) **Liquidity risk**

Prudent liquidity risk management implies maintaining sufficient cash and short-term funds and the availability of funding through an adequate amount of committed credit facilities. Management monitors rolling forecasts of the Group's liquidity and cash and cash equivalents on the basis of expected cash flow. At the end of the year the Group held cash at bank of \$10.2 million (2017: \$11.8 million).
Management monitors rolling forecasts of the Group's cash and cash equivalents on the basis of expected cash flows. This is carried out at the Group level in accordance with practice and limits set by the Group, refer to the disclosures in Note 1: Background and accounting policies-Going Concern for more information regarding the factors considered by the Company in managing liquidity risk.

The tables below analyses the Group's financial liabilities into relevant maturity groupings based on their contractual maturities for:

(a) All non-derivative financial liabilities, and
(b) Net and gross settled derivative financial instruments for which the contractual maturities are essential for an understanding of the timing of the cash flows.

The amounts disclosed in the table are the contractual undiscounted cash flows. Balances due within 12 months equal their carrying balances as the impact of discounting is not significant.

	Less than 1 year	Between 1-2 years	Between 2-5 years	Total Contractual Cash flows	Carrying amount
At 31 December 2018	$'000	$'000	$'000	$'000	$'000
Non-derivatives					
Trade and other payables	9,147	--	--	9,147	9,147
Total Non-derivatives	9,147	--	--	9,147	9,147

At 31 December 2017	$'000	$'000	$'000	$'000	$'000
Non-derivatives					
Trade and other payables	10,092	881	--	10,973	10,973
CLN (including interest)	--	7,547	3,290	10,837	3,019
Total Non-derivatives	**10,092**	**8,428**	**3,290**	**21,810**	**13,992**
Derivatives					
Trading derivatives	762	--	--	762	762

(d) **Capital risk management**

The Group's objectives when managing capital are to safeguard the Group's ability to continue as a going concern in order to provide returns for shareholders and benefits for other stakeholders and to maintain an optimal capital structure to reduce the cost of capital. In order to maintain or adjust the capital structure, the Group may adjust the amount of dividends paid to shareholders, issue new shares or sell assets to reduce debt.

Consistent with others in the industry, the Group monitors capital on the basis of the gearing ratio. This ratio is calculated as net debt divided by total capital. Net cash/ (debt) is calculated as total borrowings less cash and cash equivalents. Total capital is calculated as 'equity' as shown in the consolidated statement of financial position plus net cash/ (debt).

	2018 $'000	**2017 $'000**
CLN and borrowings*	--	3,019
Less: cash and cash equivalents	(10,201)	(11,792)
Net cash	(10,201)	(8,773)
Total equity	58,949	48,590
Total capital	48,748	39,817
Gearing ratio	(21.0)%	(22.0)%

Note (*): 2017 relates to the fair value of the CLN at 31 December 2017. The face value of the CLN's principal plus interest was $7.0 million at 31 December, 2017. In August 2018, the CLN was fully settled.

(e) **Fair value estimation**

The table below analyses financial instruments carried at fair value, by valuation method. The different levels have been defined as follows:

- Quoted prices (unadjusted) in active markets for identical assets or liabilities (Level 1).
- Inputs other than quoted prices included within level 1 that are observable for the asset or liability, either directly (that is, as prices) or indirectly (that is, derived from prices) (Level 2).
- Inputs for the asset or liability that are not based on observable market data (that is, unobservable inputs) (Level 3).

Fair value measurements using significant unobservable inputs (Level 3)

	Zero cost collar
	$'000
1 January 2018	762
Purchased	--
Payment	(1,837)
Expense	1,075
31 December 2018	**--**

3 Critical Accounting Estimates and Assumptions

The preparation of the financial statements requires the use of accounting estimates which, by definition, seldom equal the actual results. Management also exercise judgement in applying the Group's accounting policies. The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below:

(a) **Income taxes**

Some judgement is required in determining the provision for income taxes. There are certain transactions and calculations for which the ultimate tax determination is uncertain. Management recognised liabilities for anticipated tax audit issues based on estimates of whether additional taxes will be due. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the income tax and deferred tax provisions in the period in which such determination is made.

(b) **Recoverability of deferred tax assets**

Deferred tax assets mainly arise from tax losses and are recognised only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse, and a judgement as to whether or not there will be sufficient taxable profits available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. To the extent assumptions regarding future profitability change, there can be an increase or decrease in the level of deferred tax assets recognised which can result in a charge or credit in which the change occurs. The Group has concluded that the deferred tax asset recognised will be recoverable using approved business plans and budgets for the specific subsidiaries in which the deferred tax asset arose.

(c) **Provision for decommissioning costs**

This provision is significantly affected by changes in technology, laws and regulations which may affect the actual cost of decommissioning to be incurred at a future date. The estimate is also impacted by the discount rates used in the provisioning calculations. The discount rates used are the Group's risk-free rate and the core inflation rate applicable. The provision has been estimated using specific risk free rates for each asset ranging between 2.69%-2.90% (2017: 3.09%-4.65%) and a core inflation rate at 2% (2017: 3%), See Note 24: Provision for other liabilities. The impact in 2018 of a 1% change in these variables is as follows:

	Statement of Financial Position Obligation 2018 $'000	**Statement of Comprehensive Income/Expense 2018 $'000**
	(Decrease)/Increase	*Increase/(Decrease)*
Discount rate		
1% increase in assumed rate	(6,639)	95
1% decrease in assumed rate	8,083	(168)
Inflation rate		
1% increase in assumed rate	8,070	291
1% decrease in assumed rate	(6,749)	(243)

(d) **Estimation of reserves**

All reserve estimates involve some degree of uncertainty, which depends chiefly on the amount of reliable geological and engineering data available at the time of the estimate. Generally, reserve estimates are revised as additional data becomes available. The Group's reserve estimates are also evaluated when required by independent external reserve evaluators. The last independent external reserve valuation was done in 2012. Since 2012 up to and including 2018 the Group estimated its own commercial reserves based on information compiled by appropriately qualified persons relating to the geological and technical data on the size, depth, shape and grade of the hydrocarbon body and suitable production techniques and recovery rates.

As the economic assumptions used may change and as additional geological information is obtained during the operation of a field, estimates of recoverable reserves may also change. Such changes may impact the Group's reported financial position and results, which include:

- The carrying value of exploration and evaluation assets, oil and gas properties, property, plant and equipment, and goodwill may be affected due to changes in estimated future cash flows.
- Depreciation and amortisation charges in profit or loss may change where such charges are determined using the unit of production method, or where the useful life of the related assets change.
- Provisions for decommissioning may change - where changes to the reserve estimates affect expectations about when such activities will occur and the associated cost of these activities.
- The recognition and carrying value of deferred tax assets may change due to changes in the judgements regarding the existence of such assets and in estimates of the likely recovery of such assets.

As at 31 December 2018 all subsidiaries onshore and offshore proved and probable ("2P") reserve estimates were re-evaluated by management and approved by the Board.

(e) **Share-based payments**

Management is required to make assumptions in respect of the inputs used to calculate the fair values of share-based payment arrangements which include expected volatility, risk free interest rate and current share price.

(f) **Impairment of property, plant and equipment**

Management performs impairment assessments on the Group's property, plant and equipment once there are indicators of impairment with reference to IAS 36: Impairment of Assets and in accordance with the accounting policy stated in Note 1: Background and Accounting policies. In order to test for impairment, the higher of fair value less costs of disposal and values in use calculations are prepared which require arm's length offers and an estimate of the timing and amount of cash flows expected respectively to arise from the CGU. A CGU represents an individual field or asset held by the Group.

During 2018 an impairment charge of $2.6 million was recognised on the Group's property, plant and equipment (2017: no impairment) see Note 11: Property, Plant & Equipment. The impairment charge resulted in the carrying amount of the respective CGUs being written down to their recoverable amount.

(g) **Oil and Gas Assets $2.6 million (2017: nil) impairment**

As part of this assessment, management has carried out an impairment test on the oil and gas assets classified as property, plant and equipment. This test compares the carrying value of the assets at the reporting date with the recoverable amount for each CGU. The recoverable amount is the higher of the Fair Value less Costs of Disposal ("FVLCOD") and Value In Use ("VIU"). The FVLCOD is the amount that a market participant would pay for the CGU less the cost of disposal utilising a discounted cash flow approach to FVLCOD. The FVLCOD approach utilised a discounted cash flow based on the 2P reserve estimates of the CGUs of the Group. VIU is the present value of the future cash flows expected to be derived from an asset or CGU in its current condition. The period over which management has projected its cash flow forecast, ranges between 9-24 year economic lives based on the field economic life profile. For the discounted cash flows to be calculated, management has used a production profile based on its best estimate of proven and probable reserves of each CGU and a range of assumptions, including an external oil and gas price profile and a discount rate which, taking into account other assumptions used in the calculation, management considers to be reflective of the risks.

The discounted cash flow approach assessment involves judgement as to the likely commerciality of the asset; its 2P reserves which are estimated using standard recognised evaluation techniques on a fully funded basis; future revenues and estimated development costs pertaining to the CGU's; and a discount rate utilised for the purposes of deriving a recoverable value.

	2019	2020	2021	2022	2023	2024
Realised price	43.6	45.4	46.4	47.2	47.9	48.5

If the price deck used in the impairment calculation had been 10% lower than management's estimates at 31 December 2018, the group would have $3.4 million increase on impairment of Oil and Gas assets (2017: nil). If the price deck used in the impairment calculation had been 10% higher than management's estimates at 31 December 2018, the group would $0.2 million decrease on impairment of the Oil and Gas assets (2017: nil).

For the year ended 31 December 2018, management's estimate of the Group's cost of capital was 13% (2017:10%). If the estimated cost of capital in determining the post-tax discount rate for the CGU's had been 1% lower than management's estimates the Group would have $0.6 million decrease on impairment position for 2018 (2017: nil) against Oil and Gas assets within property, plant and equipment. If the estimated cost of capital had been 1% higher than management's estimates the Group would have $0.6 million increase on impairment for 2018 (2017: nil).

(h) **Impairment of intangible exploration and evaluation assets**

In 2018 a review for impairment triggers was carried out and there were no further impairment losses realised against the carrying values of the Group's Exploration and Evaluation assets.

The Group reviews the carrying values of intangible exploration and evaluation assets when there are impairment indicators which would tell whether an exploration and evaluation asset has suffered any impairment, in accordance with the accounting policy stated in Note 1: Background. The amounts of intangible exploration and evaluation assets represent the costs of active projects the commerciality of which is unevaluated until reserves can be appraised.

4 Segment Information

Management have considered the requirements of IFRS 8, in regard to the determination of operating segments, and concluded that the Group has only one significant operating segment being the production, development and exploration and extraction of hydrocarbons.

All revenue is generated from sales to one customer, Petrotrin/Heritage. All non-current assets of the Group are located in T&T.

5 Operating Profit Before Exceptional Items

	2018 $'000	2017 $'000
Operating profit before exceptional items is stated after taking the following items into account:		
DD&A (Note 11)	10,664	7,055
Amortisation of computer software (Note 12)	30	--
Employee costs (Note 31)	7,972	7,478
Operating lease rentals	568	675
Inventory recognised as expense, charged to operating expenses	175	67

Auditors' remuneration

During the year the Group (including its overseas subsidiaries) obtained the following services from the Company's Auditors as detailed below:

	2018 $'000	2017 $'000
- Fees payable to the Company's auditors' and their associates for the audit of the parent Company and consolidated financial statements:		
• PricewaterhouseCoopers LLP (UK based)	153	119
• PricewaterhouseCoopers Limited (T&T based)	95	112
- Fees payable to the Company's auditors' and their associates for other services:		
- The audit of Company's subsidiaries	18	19
- Audit related assurance services – interim review	35	30
Total assurance	301	280
- Tax advisory	3	--
- Other advisory	12	54
Total auditors' remuneration	316	334

All fees are in respect of services provided by PricewaterhouseCoopers LLP. The independence and objectivity of the external auditors are considered on a regular basis by the Audit Committee, with particular regard to the level of non-audit fees incurred.

6 Exceptional Items

Items that are material either because of their size or their nature, or that are non-recurring are considered as exceptional items and are presented within the line items to which they best relate. During the current period, exceptional items as detailed below have been included as exceptional expenses below operating profit in the Income Statement. An analysis of the amounts presented as exceptional items in these financial statements are highlighted below.

Exceptional items:	**2018 $'000**	**2017 $'000**
Reversal of bad debt written off	(205)	--
Secured creditor compromise	--	(6,472)
Unsecured creditor compromise	(70)	(15,639)
Interest on tax compromise	--	(5,247)
Foreign exchange loss on compromised balance	--	687
Impairment of property, plant and equipment (Note 11)	2,561	--
Impairment of receivables	--	234
Impairment of recompletions	--	135
Impairment of inventory	--	264
Fees relating to corporate restructuring	26	532
Gain on extinguishment of liability	--	(210)
Translation difference	--	(2)
Exceptional charge/(credit)	**2,312**	**(25,718)**

Exceptional items 2018:

Reversal of Bad debt – $0.2 million gain recovered in UK Value Added Tax ("VAT") relating to 2013 previously written off in 2017

Unsecured creditor compromise – $0.1 million gain under the creditor settlements arising from compromised balances with suppliers

Impairment on Property, Plant and Equipment – $2.6 million charge resulting from impairment losses in Onshore and West Coast assets

Fees relating to corporate restructuring – $0.0 million charge in relation to trustee fees incurred in 2018 in wrapping up the state creditor process

Exceptional items 2017:

Secured creditor compromise – $6.5 million gain under the senior debt settlement agreement where the unpaid balance was compromised

Unsecured creditor compromise – $15.6 million gain under the creditor settlements arising from compromised balances with suppliers

Interest on tax compromise – $5.2 million gain under the creditor settlement where interest outstanding was waived with the BIR

Foreign exchange loss on compromised balances – $0.7 million charge under the creditor settlements arising from compromised balances with suppliers

Impairment on receivables – $0.2 million charge resulting from impairment of deal cost UK VAT recoverable from 2013

Impairment of recompletions – $0.1 million charge resulting from impairment of recompletions

Impairment of inventory – $0.3 million charge resulting from impairment of inventory

Gain on extinguishment of liability – $0.2 million gain as a result of accounting for the liability due to the MEEI at fair value

Fees relating to corporate restructuring – $0.5 million in fees relating to the corporate restructuring of the Group include the Formal Sales Process (“FSP”), the Proposal process, the cost of advisors, as well as field restructuring

7 Net Finance Costs

	2018	**2017**
	$’000	**$’000**
Decommissioning – Unwinding of discount (Note 24)	1,557	1,643
Interest on loans	499	657
	2,056	**2,300**

8 **Income tax (expense)/ credit**

	2018 $'000	2017 $'000
Current tax		
Petroleum profits tax	5	(926)
Unemployment levy	--	(26)
Deferred tax		
- Current year		
Movement in asset due to tax losses (Note 15)	(1,794)	1,317
Movement in liability due to accelerated tax depreciation (Note 15)	3,059	(389)
Translation difference	--	(4)
Income tax expense/ (credit)	**1,270**	**(28)**

The Group's effective tax rate varies from the statutory rate for UK companies of 19.0% (2017:19.25%) as a result of the differences shown below:

	2018 $'000	2017 $'000
(Loss)/Profit before taxation	**(4,091)**	**25,320**
Tax (credit)/charge at expected rate of 19% (2017: 19.25%)	(777)	4,874
Effects of:		
Higher overseas tax rate	28	10,722
Disallowable expenses	1,917	(8,635)
Allowable expenses	(9,549)	(8,960)
Tax losses recognised for deferred tax assets	3,363	--
Tax losses utilised to recognise deferred tax assets	10,860	7,630
Deferred tax asset previously recognised	(4,197)	(5,496)
Green fund and business levy	230	149
Other differences	(605)	(312)
Income tax expense/ (credit)	**1,270**	**(28)**

Taxation losses at 31 December 2018 available for set off against future taxable profits amounts to approximately $244.1 million (2017: $226.1 million).Tax losses of $10.9 million were recognised as deferred tax assets in 2018 (2017:$7.6 million). These losses do not have an expiry date and have not yet been confirmed by the BIR and HMRC.

9 **Earnings Per Share**

Basic earnings per share is calculated by dividing the earnings attributable to ordinary shareholders by the weighted average number of ordinary shares outstanding during the year. Diluted earnings per share is calculated using the weighted average number of ordinary shares adjusted to assume the conversion of all potentially dilutive ordinary shares.

	(Loss)/ Earnings $'000	Weighted Average Number Of Shares '000'	Earnings Per Share $
Year ended 31 December 2018			
Basic	(5,321)	330,579	(0.02)
Diluted	(5,321)	330,579	(0.02)
Year ended 31 December 2017			
Basic	25,424	276,746	0.09
Diluted	25,424	395,054	0.06

Impact of dilutive ordinary shares:

There was no impact on the weighted average number of shares outstanding during 2018 as all share options and LTIP's were excluded from the weighted average dilutive share calculation because their effect would be anti-dilutive and therefore both basic and diluted earnings per share are the same in 2018.

In 2017, diluted earnings per share is calculated by adjusting the weighted average number of ordinary shares outstanding to assume conversion of all potentially dilutive ordinary shares. The Company had two categories of dilutive ordinary shares: CLNs and share based payments. The CLNs issued in 2017 were considered to be potential ordinary shares and had been included in the determination of diluted earnings per share for 2017. This is calculated as the CLN nominal value of $6.55 million plus accrued interest after the second anniversary of $1.0 million divided by the conversion price of $0.08125. Long term incentives of 24,415,998 were considered potential ordinary shares and were included in the determination of the diluted earnings per share for 2017. Share options of 1,975,084 were considered potential ordinary shares but were not included as the exercise hurdle would not have been met.

10 Investment In Subsidiaries

	Company 2018 $'000	2017 $'000
Opening balance	51,416	44,802
Capital contributed to subsidiary	6,459	6,395
Share based payment	614	219
Closing balance	**58,489**	**51,416**

The investment in subsidiaries is recognised initially at the fair value of the consideration paid. The Group subsequently measures the investment in subsidiaries at cost less impairments. Increases in the investment in subsidiaries relate to capital contributed by the Company to its subsidiary undertakings.

Listing of Subsidiaries

The Group's principal subsidiaries at 31 December 2018 are listed below:

Name	**Registered Address/Country of Incorporation**	**Nature of Business**	**% Shares held by the Group**
Bayfield Energy Limited	c/o Pinsent Masons LLP, 1 Park Row, Leeds, England, LS1 5AB, United Kingdom	Holding Company	99.99998 %
Trinity Exploration & Production (UK) Limited	13 Queen's Road, Aberdeen, AB15 4YL, United Kingdom	Holding Company	100 %
Trinity Exploration and Production Services (UK) Limited	c/o Pinsent Masons LLP, 1 Park Row, Leeds, England, LS1 5AB, United Kingdom	Service Company	100 %
Bayfield Energy do Brasil Ltda	Av. Presidente Vargas 509, Rio de Janeiro, 20071-003, Brazil	Dormant	100 %
Trinity Exploration & Production (Barbados) Limited	Ground Floor, One Welches, Welches, St. Thomas BB22025, Barbados	Holding Company	100 %
Trinity Exploration and Production (Trinidad and Tobago) Limited	3rd Floor Southern Supplies Limited Building, 40 -44 Sutton Street, San Fernando, Trinidad & Tobago ("Trinidad address")	Holding Company	100 %
Galeota Oilfield Services Limited	Trinidad address	Oil and Gas	100 %
Trinity Exploration and Production (Galeota) Limited	Trinidad address	Oil and Gas	100 %
Oilbelt Services Limited	Trinidad address	Oil and Gas	100 %
Ligo Ven Resources Limited	Trinidad address	Oil and Gas	100 %
Trinity Exploration and Production Services Limited	Trinidad address	Service Company	100 %
Tabaquite Exploration & Production Company Limited	Trinidad address	Oil and Gas	100 %
Trinity Exploration and Production (GOP) Limited	Trinidad address	Oil and Gas	100 %
Trinity Exploration and Production (GOP-1B) Limited	Trinidad address	Oil and Gas	100

11. Property, Plant and Equipment

Year ended 31 December 2018	Plant & Equipment $'000	Leasehold & Buildings $'000	Oil & Gas Assets $'000	Other $'000	Total $'000
Opening net book amount at 1 January 2018	3,767	1,726	46,957	--	52,450
Disposal	--	(6)	--	--	(6)
Additions	483	135	11,646	--	12,264
Adjustment to decommissioning estimate (Note 24)	--	--	2,076	--	2,076
Impairment[1]	--	--	(2,561)	--	(2,561)
Reclassification of assets between categories	(2,470)	--	2,470		--
DD&A charge for year	(818)	(150)	(9,696)	--	(10,664)
Translation difference	--	--	40	--	40
Closing net book amount at 31 December 2018	**962**	**1,705**	**50,932**	**--**	**53,599**
At 31 December 2018					
Cost	13,391	3,245	286,172	336	303,144
Accumulated DD&A and impairment	(12,429)	(1,540)	(235,280)	(336)	(249,585)
Translation difference	--	--	40	--	40
Closing net book amount	**962**	**1,705**	**50,932**	**--**	**53,599**

Year ended 31 December 2017	Plant & Equipment $'000	Leasehold & Buildings $'000	Oil & Gas Assets $'000	Other $'000	Total $'000
Opening net book amount at 1 January 2017	4,201	1,890	53,541	--	59,632
Disposal	--	(9)	--	--	(9)
Additions	42	2	2,824	--	2,868
Adjustment to decommissioning estimate (Note 24)	--	--	(2,868)	--	(2,868)
DD&A charge for year	(483)	(147)	(6,425)	--	(7,055)
Translation difference	7	(10)	(115)	--	(118)
Closing net book amount at 31 December 2017	**3,767**	**1,726**	**46,957**	**--**	**52,450**
At 31 December 2017					
Cost	12,901	3,126	272,565	336	288,928
Accumulated DD&A and impairment	(9,141)	(1,390)	(225,493)	(336)	(236,360)
Translation difference	7	(10)	(115)	--	(118)
Closing net book amount	**3,767**	**1,726**	**46,957**	**--**	**52,450**

1 *An impairment loss of $2.6 million was recognised on Oil and Gas Assets (see Note 3 g (i)) as a result of the carrying value being higher than the recoverable amount. The recoverable amount was determined by assessing its fair value less costs of disposal.*

12. Intangible Assets

The carrying amounts and changes in the year are as follows:

	Computer Software $'000	Exploration and evaluation assets $'000	Total $'000
At 1 January 2018	250	25,341	25,591
Computer software	26	--	26
Exploration and evaluation assets	--	170	170
Amortisation	(30)	--	(30)
At 31 December 2018	**246**	**25,511**	**25,757**
At 1 January 2017	--	25,406	25,406
Computer software	250	--	250
Translation difference	--	(65)	(65)
At 31 December 2017	**250**	**25,341**	**25,591**

- Computer Software: In 2018, capital cost incurred for accounting software
- Exploration and evaluation assets: Includes the TGAL-1 exploration well and associated cost.

The Group tests whether exploration and evaluation assets has suffered any impairment triggers on an annual basis and there were no impairment triggers (2017: nil)

13 Abandonment Fund

	2018 $'000	2017 $'000
At 1 January	1,650	1,072
Additions	1,329	578
At 31 December	**2,979**	**1,650**

Abandonment funds are restricted cash put aside in escrow for abandonment and environmental purposes in accordance with contractual obligations to be used in accordance with the contract.

14 Performance Bond

	2018 $'000	2017 $'000
At 1 January	253	--
Additions	--	253
At 31 December	**253**	**253**

A performance bond was put in place on 3 July 2017 of $ 0.3 million at 1.75% rate per annum in favour of Petrotrin/Heritage, executed with First Citizens Bank Limited (T&T based bank) and is effective until 31 December 2020. These funds have been restricted to a Fixed Deposit for 36 months at the agreed interest rate of 1.25%. The performance bond is a requirement under the Lease Operatorship Agreement ("LOAs") as Trinity is the Operator of the FZ2, WD2, WD 5/6, WD 13 and WD 14 fields.

15 Deferred Income Taxation

Group

The analysis of deferred tax assets is as follows:

	2018 $'000	2017 $'000
Deferred tax assets:		
-Deferred tax assets to be recovered in more than 12 months	(5,238)	(4,179)
-Deferred tax assets to be recovered in less than 12 months	(735)	--
Deferred tax liabilities:		
-Deferred tax liabilities to be settled in more than 12 months	5,598	2,538
Net deferred tax assets	**(375)**	**(1,641)**

The movement on the deferred income tax is as follows:

	2018 $'000	2017 $'000
At beginning of year	(1,641)	(2,569)
Movement for the year	1,334	986
Unwinding of deferred tax on fair value uplift	(68)	(58)
Net deferred tax asset	**(375)**	**(1,641)**

The deferred tax balances are analysed below:

	2016 $'000	Movement $'000	2017 $'000	Movement $'000	2018 $'000
Deferred tax assets					
Acquisition	(33,436)	--	(33,436)	--	(33,436)
Tax losses recognised	(34,293)	--	(34,293)	(1,794)	(36,087)
Tax losses derecognised	62,233	1,317	63,550	--	63,550
	(5,496)	**1,317**	**(4,179)**	**(1,794)**	**(5,973)**

Deferred tax liabilities	2016 $'000	Movement $'000	2017 $'000	Movement $'000	2018 $'000
Accelerated tax depreciation	14,374	(331)	14,043	3,128	17,171
Non-current asset impairment	(33,214)	--	(33,214)	--	(33,214)
Acquisitions	19,580	--	19,580	--	19,580
Fair value uplift	2,187	(58)	2,129	(68)	2,061
	2,927	**(389)**	**2,538**	**3,059**	**5,598**

- Deferred tax assets are recognised for tax loss carry-forwards to the extent that the realisation of the related tax benefit through future taxable profits are probable. Deferred tax assets of $1.8 million has been recognised for the year (2017: $1.3 million was de-recognised) based on future taxable profits. The Group has unrecognised deferred tax assets amounting to $117.7 million which have no expiry date.
- Deferred tax liabilities have increased by $3.1 million as the carrying values of property, plant and equipment and intangible assets was higher than the tax written down values.
- Deferred tax assets and deferred tax liabilities can only be offset in the Statement of Financial Position if an entity has a legal right to settle current tax amounts on a net basis and Deferred Tax amounts are levied by the same tax authority (as per IAS 12).

16 Inventories

	Crude oil	Materials and supplies	Total
	$'000	$'000	$'000
At 1 January 2018	130	3,636	3,766
Net inventory movement	(41)	13	(28)
At 31 December 2018	**89**	**3,649**	**3,738**
At 1 January 2017	120	3,667	3,787
Inventory movement	10	233	243
Impairment	--	(264)	(264)
At 31 December 2017	**130**	**3,636**	**3,766**

(i) Assigning costs to inventories

The costs of individual items of inventory within the category material and supplies are determined using weighted average costs. The cost assigned for crude oil is based on the lower of cost and net realisable value.

(ii) Amounts recognised in profit or loss

Inventories recognised as an expense during the year ended 31 December 2018 amounted to $0.2 million (2017: $0.1 million); these were included in production costs.

At the end of 2018 there were no impairments (2017: $0.3 million impairment loss).

17 Trade and Other Receivables

	Group		Company	
	2018	2017	2018	2017
	$'000	$'000	$'000	$'000
Due after more than one year				
Amounts due from Group companies (Note 26 (d))	--	--	--	--
Due within one year				
Amounts due from related parties (Note 26 (d))	--	--	6,539	2,447
Trade receivables	10,408	3,272	--	--
Less: provision for impairment of trade receivables	--	--	--	--
Trade receivables – net	10,408	3,272	6,539	2,447
Prepayments	846	631	50	58
VAT recoverable	1,610	807	34	31
Other receivables	479	445		--
	13,343	**5,155**	**6,623**	**2,536**

The fair value of trade and other receivables approximate their carrying amounts.

The Group applies the IFRS 9 simplified model for measuring ECL which uses a lifetime expected loss allowance and are measured on the days past due criterion. Amounts due from related parties are repayable on demand and entities have the ability to repay if called immediately.

Having reviewed past payment performance combined with the credit rating of Petrotin/Heritage in order to assess the potential for impairment, the Group has concluded this to be insignificant as there has been no history of default or disputes arising on invoiced amounts in the past 5 years and as such the credit loss % is assumed to be almost zero.

Trade receivables that are less than six months past due are not considered impaired and at 31 December 2018, trade receivables of $10.4 million (2017: $3.3 million) were considered to be fully performing. There was a delay in collecting trade receivables for October and November amounting to $6.7 million due to the restructuring of the Group's sole customer Petrotrin/ Heritage. However, subsequent to the year-end $4.1 million of these have been collected to date and Management remain confident that the remaining balance of $2.6 million will be collected during H1 2019.

At the end of 2017 there was an impairment of $0.3 million relating to UK VAT on invoices that were no longer recoverable.

Ageing analysis of these trade receivables as at 31 December is as follows:

	2018	**2017**
	$'000	**$'000**
Up to 30 days	7,616	3,272
30 – 60 days	2,792	--
	10,408	**3,272**

The carrying amount of the Group's trade and other receivables are denominated in the following currencies:

	Group		**Company**	
	2018	**2017**	**2018**	**2017**
	$'000	**$'000**	**$'000**	**$'000**
USD	7,918	2,631	6,547	2,464
GBP	62	60	76	72
TTD	5,363	2,464	--	--
	13,343	**5,155**	**6,623**	**2,536**

The maximum exposure to credit risk at the reporting date is the value of each class of receivable as shown above. The Group does not hold any collateral as security.

The credit quality of the financial assets that are neither past due nor impaired can be assessed by reference to historical information about the counterparty default rates:

	Group		**Company**	
	2018	**2017**	**2018**	**2017**
	$'000	**$'000**	**$'000**	**$'000**
Trade receivables				
Counterparties without external credit rating:				
Existing customers with no defaults in the past	**10,408**	**3,272**	**--**	**--**

All trade receivables are with the Group's only customer, Petrotrin/Heritage.

18 Cash and Cash Equivalents

	Group		Company	
	2018	2017	2018	2017
	$'000	$'000	$'000	$'000
Cash and cash equivalents	10,201	11,792	4,056	6,024
	10,201	**11,792**	***4,056***	***6,024***

Cash and cash equivalents disclosed above and in the statement of cash flows exclude restricted cash and are available for general use by the Group. At the end of the year the cash balance was impacted due to the restructuring of the Group's sole customer Petrotrin/Heritage where $6.7 million in trade receivables relating to October and November were not received within the expected payment terms. .These are included within the Group's trade receivables (see Note 17: Trade and other receivables). Subsequent to the year-end $4.1 million of these trade receivables have been collected to date and Management remain confident that the outstanding $2.6 million will be collected during H1 2019.

19 Share Capital and Share Premium

	Number of shares No.	Ordinary shares $'000	Share premium $'000	Total $'000
As at 1 January 2018	282,399,986	96,676	125,362	222,038
Issue of shares	101,649,260	1,016	14,517	15,533
As at 31 December 2018	**384,049,246**	**97,692**	**139,879**	**237,571**
As at 1 January 2017	94,799,986	94,800	116,395	211,195
Share Capital Reorganisation ("SCR")	187,600,000	1,876	8,967	10,843
As at 31 December 2017	**282,399,986**	**96,676**	**125,362**	**222,038**

In July, 2018 the Company raised gross proceeds of $20.0 million pursuant to the Fundraising comprising of $13.6 million proceeds of shares issuance and $6.4 million from conversion of CLNs (Note 23- Convertible loan notes). Details of the fundraising as follows:

- Certain existing and new institutional investors in the Company participated in the Placing of 56,370,645 new ordinary shares;
- Directors and senior management subscribed for 2,398,185 new ordinary shares;;
- 88% of CLN holders elected to convert their redeemable CLNs into 32,715,504 new ordinary shares; and
- Other qualifying participants had the opportunity to subscribe for 10,164,926 new ordinary shares

Originally the CLN was recorded at its fair value which was significantly lower than its face value. Upon conversion and settlement of the CLN holders, this $3.3 million discount was credited to share premium.

Year ended 31 December 2018		No. of Shares	Ordinary Shares $'000	Deferred Shares $'000	Share Premium $'000	Total $'000
At 1 January 2018		282,399,986	2,824	93,852	125,362	222,038
New ordinary shares issued	0.01	101,649,260	1,016	--	--	1,016
Ordinary share premium	0.19	--	--	--	18,984	18,984
CLN discount		--	--	--	(3,265)	(3,265)
Cost of raising equity		--	--	--	(1,202)	(1,202)
At 31 December 2018		**384,049,246**	**3,840**	**93,852**	**139,879**	**237,571**
Note: $:GBP rate 1.312:1						

Year ended 31 December 2017			$'000	$'000	$'000	$'000
At 1 January 2017	1.00	94,799,986	94,800	--	116,395	211,195
SCR	1.00	(94,799,986)	(94,800)	--	--	(94,800)
New ordinary shares following the SCR	0.01	94,799,986	948	--	--	948
Deferred ordinary shares following SCR	0.99	--	--	93,852	--	93,852
New ordinary shares issued	0.01	187,600,000	1,876	--	--	1,876
Ordinary share premium	0.05	--	--	--	9,849	9,849
Cost of raising equity		--	--	--	(882)	(882)
At 31 December 2017		**282,399,986**	**2,824**	**93,852**	**125,362**	**222,038**
Note: $:GBP rate 1.255:1						

20 Share Based Payment Reserve

The share-based payments reserve is used to recognise:

- The grant date fair value of options issued to employees but not exercised
- The grant date fair value of shares issued to employees
- The grant date fair value of deferred shares granted to employees but not yet vested
- The issue of shares held by the Employee Share Trust to employees.

During 2018 the Group had in place share-based payment arrangements for its employees and Executive Directors, the Share Option Plan and the LTIP. The charge in relation to these arrangements is shown below, with further details of each scheme following:

	2018 $’000	2017 $’000
At 1 January	12,553	12,244
Share based payment expense:		
LTIP	737	309
At 31 December	**13,290**	**12,553**

Share Option Plan

Share options are granted to Executive Directors and to selected employees. The exercise price of the granted option is equal to management's best estimate of the fair value of the shares at the time of the award of the options. The Group has no legal or constructive obligation to repurchase or settle the options in cash.

At 31 December 2018, the Group had two employee share option plans which were fully vested.

Share Options outstanding at the end of the year have the following expiry date and exercise prices:

		2018		2017	
Grant-Vest	**Expiry Date**	**Exercise price per share options**	**Number of Options**	**Exercise price per share options**	**Number of Options**
2012-2015	2022	GBP0.86	1,685,540	GBP0.86	1,685,540
2013-2016	2023	GBP1.20	289,544	GBP1.20	289,544
			1,975,084		1,975,084

The inputs into the Black-Scholes model for options granted in prior periods were as follows:

Grant date	29 May 2013	14 February 2013
Share price	GBP 1.19	GBP 1.20
Average Exercise price	GBP 1.20	GBP 0.89
Expected volatility	55%	78%
Risk-free rates	4.5%	4.5%
Expected dividend yields	0%	0%
Vesting period	3 years	3 years

Long Term Incentive Plan ("LTIP")

LTIP awards are designed to provide long-term incentives for Senior Managers and Executive Directors to deliver long-term shareholder returns. Under the plan, participants are granted options which only vest if certain performance standards are met. Participation in the plan is at the Board's discretion and no individual has a contractual right to participate in the plan or to receive any guaranteed benefits.

LTIP awards were granted in August 2017 over 25,415,998 ordinary shares ("2017 LTIP Award"). The 2017 LTIP Awards will normally vest on 30 June 2022, although they may vest in full or in part on 30 June 2020 or 2021 subject to meeting performance targets relating to:

- In respect of 70% of the award, the Company's share price growth from the 2017 placing price of 4.98 pence per share. If the 3 month volume-weighted price ("VWAP") at the testing date is 35 pence or more per share, this part of the award will vest in full. If the VWAP at the testing date is 4.98 pence per share or less, this part of the award will not vest at all. If the VWAP at the testing date is between 4.98 pence and 35 pence per share, this part of the award will vest on a pro-rated straight-line basis;

- In respect of 20% of the award, repayment of the amount due to the BIR on or before 30 September 2019, in accordance with the terms of the Creditors Proposal approved in 2017. The final payment occurred following completion of the Fundraising in 2018; and

- In respect of 10% of the award, redemption of all the CLNs issued in January 2017 before the second anniversary of their issue. All of the CLNs were redeemed as part of the Fundraising in 2018.

All remaining awards under the LTIP (which were granted in 2013) lapsed during 2017 as the performance targets were not satisfied.

Movements in the number of LTIPs outstanding and their related weighted average exercise prices are as follows:

	2018 Average exercise price per share option	**Number of Options**	**2017 Average exercise price per share option**	**Number of Options**
At 1 January	GBP 0.00	25,415,998	GBP 0.00	189,600
Lapsed		--	GBP 0.00	(189,600)
Granted during the year		--	GBP 0.00	25,415,998
At 31 December	GBP 0.00	25,415,998	GBP 0.00	25,415,998

LTIPs outstanding at the end of the year have the following expiry date and exercise prices:

Grant-Vest	**Expiry date**	**Exercise price**	**2018**	**2017**
2017-2022	2022	GBP 0.00	25,415,998	25,415,998

The total fair value of the 2017 LTIP Award is $2.6 million and will be expensed over the vesting period with the full charge pro-rated over the period up to 30 June 2022. However, the LTIP Award may vest in full or in part on 30 June 2020 or 2021 with the appropriate charge being taken at that time. The fair value at grant date is independently determined using an adjusted form of the Black Scholes Model which includes a Monte Carlo simulation model that takes into account the exercise price, the term of the option, the share price at grant date and expected price volatility of the underlying share, the expected dividend yield, the risk free interest rate for the term of the option and the correlations and volatilities of the peer group companies. The model inputs for LTIP Awards granted in 2017:

Grant Date	24 August 2017
Share price at grant date	GBp10.75
Exercise price	GBP0.00
Expected volatility	73.3%
Risk-free interest rates	0.44%
Expected dividend yields	0%
Vesting period 1	30 June 2020
Vesting period 2	30 June 2021
Vesting period 3	30 June 2022

21 Merger and Reverse Acquisition Reserves

	Reverse Acquisition Reserve $'000	Merger Reserve $'000	Total $'000
At 1 January 2018	(89,268)	75,467	(13,801)
Movement	--	--	--
Translation differences	--	--	--
At 31 December 2018	**(89,268)**	**75,467**	**(13,801)**
At 1 January 2017	(89,268)	75,467	(13,801)
Movement	--	--	--
Translation differences	--	--	--
At 31 December 2017	**(89,268)**	**75,467**	**(13,801)**

The issue of shares by the Company as part of the reverse acquisition met the criteria for merger relief such that no share premium was recorded. As allowed under the UK Companies Act 2006 and required by IAS 27 ('Consolidated and separate financial statements'), a merger reserve equal to the difference between the fair value of the shares acquired by the Company and the aggregation of the nominal value of the shares issued by the Company has been recorded.

The insertion of the Company as the new parent to the Group has been accounted for using business combination accounting as described in Note 1: Background and Accounting policies. The reverse acquisition difference recorded in the consolidated financial statements represents the difference in accounting for reverse acquisition transactions.

22 Adjusted EBITDA

Adjusted EBITDA is a non-IFRS measure used by the Group to measure business performance. It is calculated as Operating Profit before SPT and PT for the period, adjusted for DD&A, share option expenses and Other Expenses (derivative hedge instruments).

The Group presents Adjusted EBITDA as it is used in assessing the Group's growth and operational efficiencies as it illustrates the underlying performance of the Group's business by excluding items not considered by management to reflect the underlying operations of the Group.

Adjusted EBITDA is calculated as follows:

	2018 $'000	2017 $'000
Operating Profit Before SPT and PT	6,720	3,932
DD&A	10,694	7,055
Share option expenses	737	235
Loss on oil derivative hedge instruments	1,075	1,362
Adjusted EBITDA	19,226	12,584
	'000	'000
Weighted average ordinary shares outstanding - basic	330,579	276,746
Weighted average ordinary shares outstanding - diluted	355,995	395,054
	$	$
Adjusted EBITDA per share - basic	0.058	0.045
Adjusted EBITDA per share - diluted	0.054	0.032

Adjusted EBITDA after the impact of SPT and PT is calculated as follows:

	2018 $'000	2017 $'000
Adjusted EBITDA	19,226	12,584
SPT	(7,050)	(1,533)
PT	607	(497)
Adjusted EBITDA After SPT and PT	12,783	10,554
	'000	'000
Weighted average ordinary shares outstanding - basic	330,579	276,746
Weighted average ordinary shares outstanding - diluted	355,995	395,054
	$	$
Adjusted EBITDA After SPT and PT per share - basic	0.039	0.038
Adjusted EBITDA After SPT and PT per share - diluted	0.036	0.027

23 Convertible Loan Notes ("CLN")

On 11 January 2017 the Company issued at a 50% discount 6,550,000 one dollar, unsecured CLNs. The notes mature 7 years from the issue date at their nominal value of $6.55 million plus quarterly accrued, aggregated and compounded interest. Repayments or conversion prior to the maturity date can be made in certain circumstances:

- *Early Redemption*
  Subject to the settlement of the debts owed to the BIR and the MEEI the Company before the second anniversary of the CLN's issue date, redeem all or a portion of the CLN giving 5 business days' written notice to the Noteholder. The Noteholders do not have the option to convert under this arrangement.

- *Redemption*
  The Company can, after satisfying the debts owed to the BIR and the MEEI or after two years from the issue dates (whichever is the latter), elect to redeem all the CLN before the maturity date. The redemption date in this scenario must not be less than 20 days from the Early Redemption Notice. The Noteholders can serve a Conversion Notice.

- *Conversion*
  Each Noteholder can after the second anniversary of the issue date serve a Conversion Notice. The principal amount plus the outstanding interest shall be converted into new fully paid ordinary shares at a Conversion Price of $0.08125.

On 12 July 2018, $6.4 million in relation to the holders of CLNs opted to convert the value of their CLNs inclusive of accrued interest in ordinary shares and on 15 August 2018 the remaining holders of the CLNs who did not elect to convert their CLNs pursuant to the subscription were repaid in cash, which amounted to $0.9 million.

Year ended 31 December 2018	**Total $'000**
Opening amount as at 1 January 2018	3,019
Effective interest	118
Interest accrued[2]	300
Equity component	590
Share premium (difference in fair value on CLN)	3,265
Settlement of CLN via conversion to ordinary shares	(6,437)
Settlement of CLN in Cash	(864)
Translation difference	9
Closing balance at 31 December 2018	**--**
Year ended 31 December 2017	
Opening amount as at 1 January 2017	--
Nominal value of CLN issued[1]	6,550
Issued at a 50% discount	(3,275)
Fair value of CLN	3,275
Expenses incurred	(245)
Fair value of CLN (net of costs)	3,030
Equity component	(590)
Liability component at initial recognition	2,440
Effective interest	105
Interest accrued[2]	474
Closing balance at 31 December 2017	**3,019**

Notes:
[1]The amount repayable on the CLN is the nominal value of $6.6 million plus accrued interest.
[2] Interest is calculated by applying the effective interest rate of 23.7 % to the liability component.

In 2017 the CLN was initially recognised and measured at its fair value of $3.3 million. The fair value of the liability component was determined using a market interest rate of 22.4% for an equivalent non-convertible bond at the issue date. The liability is subsequently recognised on an amortised cost basis until extinguished on conversion or maturity of the notes. The remainder of the proceeds are allocated to the conversion option and recognised in shareholders' equity net of transaction cost, and not subsequently re-measured.

24 Provision for Other Liabilities

(a) Non-current:

	Decommissioning cost $'000	Employee Retirement Benefit $'000	Total $'000
Year ended 31 December 2018			
Opening amount as at 1 January 2018	37,151	--	37,151
Unwinding of discount (Note 7)	1,557	--	1,557
Increase in provisions for new wells	1,164	--	1,164
Revision to estimates	867	--	867
Decommissioning contribution	1,074	--	1,074
Translation differences	(11)	--	(11)
Closing balance at 31 December 2018	**41,802**	**--**	**41,802**
Year ended 31 December 2017			
Opening amount as at 1 January 2017	37,970	348	38,318
Unwinding of discount (Note 7)	1,643	--	1,643
Restructuring provision settled	--	(348)	(348)
Revision to estimates	(2,868)	--	(2,868)
Decommissioning contribution	497	--	497
Translation differences	(91)	--	(91)
Closing balance at 31 December 2017	**37,151**	**--**	**37,151**

Decommissioning cost

The Group operates Oil fields and this cost represents an estimate of the amounts required for abandonment of the Group's wells, platforms, gathering station and pipeline infrastructures. The amounts are calculated based on the provisions of existing contractual agreements with Petrotrin/Heritage and MEEI. Furthermore, liabilities for decommissioning costs are recognised when the Group has an obligation to dismantle and remove a facility or an item of plant and to restore the site on which it is located, and when a reasonable estimate of that liability can be made. An obligation for decommissioning may also crystallise during the period of operation of a facility through a change in legislation or through a decision to terminate operations.

The amount recognised is the present value of the estimated future expenditure determined in accordance with local conditions and requirements. A corresponding item of property, plant and equipment of an amount equivalent to the provision is also created. This is subsequently depreciated as part of the capital costs of the facility or item of plant. Any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding property, plant and equipment. Some of the key assumptions made in the present value decommissioning calculation include the following:

a. Core inflation rate – 2% (2017: 3%)
b. Risk free rate – 2.69% - 2.90% (2017: 3.09% - 4.65%)
c. Estimated market value/decommissioning cost
d. Estimated life of each asset

See Note 3(c): Critical Accounting Estimates and Assumptions for the rates used and sensitivity analysis.

Employee Retirement benefit

In 2017 the employee retirement benefit provision was extinguished under the restructuring process.

(b) Current:

	Litigation claims $'000	Closure of Pits $'000	Total $'000
Year ended 31 December 2018			
Opening amount as at 1 January 2018	115	--	115
Increase in provision	--	232	232
Closing balance at 31 December 2018	**115**	**232**	**347**
Year ended 31 December 2017			
Opening amount as at 1 January 2017	470	--	470
Decrease in provision	(355)	----	(355)
Closing balance at 31 December 2017	**115**	**--**	**115**

Litigation claims
In 2017 the Litigation claims were written down to the compromised amount.

Closure of Pits
In 2018 there was an increase in the provision of $0.2 million relating to the remedy and closure of pits associated with drilling new onshore wells

25 Trade and Other Payables

(a) Non- Current:	Group		Company	
	2018 $'000	2017 $'000	2018 $'000	2017 $'000
Due to BIR Interest on taxes[1]	--	417	--	--
Due to MEEI[2]	--	231	--	--
Other Payables	--	233	--	--
	--	**881**	**--**	**--**

(b) Current:	2018 $'000	2017 $'000	2018 $'000	2017 $'000
Trade payables	3,076	555	58	67
Accruals	3,454	2,547	423	454
VAT payable	--	272	--	--
Other payables	701	701	--	--
SPT and PT	1,916	2,626	--	--
Due to BIR Interest on taxes and SPT[1]	--	2,865	--	--
Due to MEEI[2]	--	526	--	--
	9,147	**10,092**	**481**	**521**

Notes:

1. *The amounts due to the BIR under the settlement agreement was fully repaid in 2018.*
2. *The amounts due to the MEEI under the settlement agreement was fully repaid in 2018*

26 Related Party Transactions

Group

The following transactions were carried out with the Group's subsidiaries and related parties. These transactions comprise sales and purchases of goods and services and funding provided in the ordinary course of business. The following are the major transactions and balances with related parties:

(a) Sales of services and loans issued to subsidiaries

	Group		Company	
	2018	**2017**	**2018**	**2017**
	$'000	**$'000**	**$'000**	**$'000**
Group subsidiaries:				
Trinity Exploration and Production Services (UK) Limited	--	--	3,176	347
Trinity Exploration and Production (UK) Limited	--	--	14	--
Trinity Exploration and Production (Galeota) Limited	--	--	13	(498)
Bayfield Energy Limited	--	--	14	--
Oilbelt Services Limited	--	--	1,197	--
Trinity Exploration and Production (Trinidad and Tobago) Limited	--	--	(501)	910
Trinity Exploration and Production Services Limited	--	--	179	(168)
	--	**--**	**4,092**	**591**

Related party sales transactions and loans issued to subsidiaries are exchanged at arm's length and are comparable to terms that would be available to third parties.

(b) Purchases of services

	Group		Company	
	2018	**2017**	**2018**	**2017**
	$'000	**$'000**	**$'000**	**$'000**
Related party:				
Trinity Exploration and Production Services (UK) Limited	--	--	--	(335)
	--	**--**	**--**	**(335)**

(c) Key Management and Directors' compensation

Key Management includes Directors (Executive & Non-Executive) and the Country Manager. The compensation paid or payable to Key Management for employee services is shown below:

	Group	
	2018	**2017**
	$'000	**$'000**
Salaries and short-term employee benefits	1,108	993
Post-employment benefits	33	53
Share-based payment expense (Note 20)	737	309
	1,878	**1,355**

(d) Year-end balances arising from sales/purchases of services

	Group		Company	
	2018	2017	2018	2017
	$'000	$'000	$'000	$'000
Receivables from related parties:				
Trinity Exploration and Production Services Limited	--	--	867	688
Trinity Exploration and Production (UK) Limited	--	--	14	--
Trinity Exploration and Production (Galeota) Limited	--	--	13	--
Bayfield Energy Limited	--	--	14	--
Oilbelt Services Limited	--	--	1,197	--
Trinity Exploration and Production (Trinidad) Limited	--	--	408	909
Trinity Exploration and Production Services (UK) Limited	--	--	4,026	850
	--	**--**	**6,539**	**2,447**
Payables to related parties:				
Trinity Exploration and Production Services Limited	--	--	--	--
Trinity Exploration and Production Services (UK) Limited	--	--	--	--
	--	**--**	**--**	**--**

Group and Company

The receivables from related parties arise mainly from sales. The receivables are unsecured and bear no interest. No provisions are held against receivables from related parties (2017: nil).

The payables to related parties arise mainly from purchase transactions and are due two months after the date of purchase. The payables bear no interest.

27 Derivative financial instruments

	31 December 2018	31 December 2017
	$'000	$'000
Zero cost collar	--	762
	--	**762**

28 Taxation Payable

	Group		Company	
	2018	2017	2018	2017
	$'000	$'000	$'000	$'000
<u>Taxation payable</u>				
PPT/ UL	--	66	--	--
Due to BIR (PPT, CT and UL)[1]	--	1,622	--	--
	--	**1,688**	**--**	**--**

Notes:

1. *2018 nil balance. 2017: Due to the BIR under the settlement agreement is PPT; CT and UL taxes of* $1.6 million

29 Financial Instruments by Category

At 31 December 2018 and 2017, the Group held the following financial assets at amortised cost:

	Group		Company	
	2018	2017	2018	2017
	$'000	$'000	$'000	$'000
Trade and other receivables – current	13,343	5,155	6,623	2,536
Abandonment fund – non current	2,979	1,650	--	--
Cash and cash equivalents	10,201	11,792	4,056	6,024
	26,523	**18,597**	**10,679**	**8,560**

At 31 December 2018 and 2017, the Group held the following financial liabilities at amortised cost:

	Group		Company	
	2018	2017	2018	2017
	$'000	$'000	$'000	$'000
Accounts payable and accruals	9,147	10,092	481	521
Convertible Loan Note	--	3,019	--	3,019
	9,147	**13,111**	**481**	**3,540**

At 31 December 2018 and 2017, the Group held the following financial liabilities at fair value:

	Group		Company	
	2018	2017	2018	2017
	$'000	$'000	$'000	$'000
Derivative financial instrument	--	762	--	762
	--	**762**	**--**	**762**

30 Commitments and Contingencies

a) Commitments

There are commitments for decommissioning costs of the wells and facilities under the Group's agreements with Petrotrin/ Heritage, which have been provided for as described in Note 24: Provision for other liabilities.

The Group leases vehicles, offices and copiers under cancellable operating lease agreements. The lease terms are between 1 and 5 years, and the majority of lease agreements are renewable at the end of the lease period. The lease expenditure charged to the income statement during the year is as follows:

	Group	
	2018	2017
	$'000	$'000
Not later than 1 year	139	534
Later than 1 year and no later than 5 years	21	34
	160	**568**

b) Contingent Liabilities

i) The farm-out agreement for the Tabaquite Block (held by Coastline International Inc.) has expired. There may be additional liabilities arising when a new agreement is finalised, but these cannot be presently quantified until a new agreement is available.
ii) Parent company guarantee. A Letter of Guarantee has been established over the Point Ligoure, Guapo Bay & Brighton ("PGB") Block where a subsidiary of Trinity is obliged to carry out a Minimum Work Programme to the value of $8.4 million. The guarantee shall be reduced at the end of each twelve month period upon presentation of all technical data and results of the Minimum Work Programme performed.
iii) The Group is party to various claims and actions. Management have considered the matters and where appropriate has obtained external legal advice. No material additional liabilities are expected to arise in connection with these matters, other than those already provided for in these financial statements.
iv) On 3 June 2017 a performance bond was established by the Group's Lease Operatorship Assets ("LOA"). A performance bond in the form of a cash deposit of $0.3 million in the name of the beneficiary Petrotrin/ Heritage was established for due and punctual observance of the matters under the LOA effective until 31 December 2020.

31 Employee Costs

Employee costs for the Group during the year	2018 $'000	2017 $'000
Wages and salaries	6,602	6,778
Other pension costs	633	391
Share based payment expense (Note 20)	***737***	***309***
	7,972	***7,478***

Average monthly number of people (including Executive and Non-Executive Directors') employed by the Group	2018 number	2017 number
Executive and Non-Executive Directors	6	5
Administrative staff	76	64
Operational staff	120	122
	202	**191**

32 Events after the Reporting Year

1. On 2 January 2019 the Company issued awards under its LTIP ("2019 LTIP award"). The Company awarded the grant of Options over 2,824,000 ordinary shares (representing 0.735% of the Company's issued share capital) under the 2019 LTIP award. The LTIP Awards are subject to the achievement of relative Total Shareholder Return ("TSR") performance targets measured over a three year performance period ending on 1 January 2021. These awards have been made in accordance with the policy announced to the market on 25 August 2017 and have been made to certain individuals in respect of the performance of the Group as at the end of the financial year ended 31 December 2017.

2. On 15 January 2019, the Group announced that the effective transition date to the new national oil company, Heritage was 1 December 2018 and the restructuring process with Petrotrin to date is ongoing. There have been some delays in the timing of payments for October and November crude oil revenues from Petrotrin with an amount outstanding of $6.7 million at year end. The Group has received $4.1 million of these delayed payments to date, with the remaining $2.6 million which is outstanding expected to be collected during H1 2019.