Trinity Exploration & Production plc

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

Preliminary Results
"Strong Operational and Financial Performance"

Trinity, the independent E&P company focused on Trinidad & Tobago ("T&T"), today announces its unaudited preliminary results for the 12 months ended 31 December 2019 ("the period" or "FY 2019").

2019 was a significant year for Trinity as we delivered another strong operational and financial performance as well as deploying new operating approaches, technologies and techniques, with the aim of becoming a more technologically focused operator and thereby driving optimum operational, financial and environmental performance. Despite lower oil price realisations, these efficiencies helped deliver another year of growth in our Adjusted EBITDA to USD 21.8 million, an increase in cash balances to USD 13.8 million at year end, and a further reduction in our operating break-even to USD 26.4/bbl.

Key Performance Indicators

		FY 2019	**FY 2018**	**Change %**
Average realised oil price[1]	*USD/bbl*	58.1	59.8	(3)
Average net production	*bopd*	3,007	2,871	5
Revenues	*USD million*	63.9	62.6	2
Operating Expenses	*USD million*	53.6	55.9	(4)
Operating Profit before SPT & PT	*USD million*	10.3	6.7	54
Adjusted EBITDA[2]	*USD million*	21.8	19.2	14
Adjusted EBITDA[3]	*USD/bbl*	19.8	18.3	9
Adjusted EBITDA margin[4]	*%*	34	31	11
Adjusted EBITDA after SPT & PT[5]	*USD million*	13.9	12.8	9
Consolidated operating break-even[6]	*USD/bbl*	26.4	29.0	(9)
Cash balance	*USD million*	13.8	10.2	35
Net cash plus working capital surplus[7]	*USD million*	17.3	18.1	(4)

Notes:
1. *Realised price: Actual price received for crude oil sales per barrel ("bbl")*
2. *Adjusted EBITDA (USD million): Operating Profit before Taxes for the period, adjusted for DD&A, non-cash SOE, ILFA and hedge costs*
3. *Adjusted EBITDA (USD/bbl): Adjusted EBITDA/Annual production.*
4. *Adjusted EBITDA margin (%): Adjusted EBITDA/Revenues.*
5. *Adjusted EBITDA after Supplemental Petroleum Tax ("SPT") & Property Tax ("PT") (USD million): Adjusted EBITDA after SPT & PT.*
6. *Consolidated operating break-even: The realised price where Adjusted EBITDA for the entire Group is equal to zero.*
7. *Net cash plus working capital surplus: Current Assets less Current Liabilities (other than Provisions for other liabilities).*

Financial Highlights

- Revenues increased by 2% to USD 63.9 million (2018: USD 62.6 million)
- Cash operating costs down 9% to USD 15.0/bbl (2018: USD 16.9/bbl)
- Adjusted EBITDA increased 14% to USD 21.8 million (2018: USD 19.2 million)
- Adjusted EBITDA margin of 34% (2018: 31%) or USD 19.8/bbl (2018: USD 18.4/bbl)
- Adjusted EBITDA after SPT & PT up 9% to USD 13.9 million (2018: USD 12.8 million)
- Group operating break-even price reduced by 9% to USD 26.4/bbl (2018: USD 29.0/bbl)
- Cash balance of USD 13.8 million (2018: USD 10.2 million)
- Cash plus working capital surplus of USD 17.3 million (2018: USD 18.1 million)
- Working capital facility put in place (undrawn at year end but fully drawn-down effective 2 April 2020) with CIBC FirstCaribbean (Trinidad & Tobago) Limited ("CIBC") for USD 2.7 million repayable upon demand, providing further financial flexibility

Operational Highlights

- Average production volumes grew in aggregate by 5% to 3,007 bopd in 2019 (2018: 2,871 bopd)
- Operational strategy centred around preserving base production, whilst retaining flexibility with multiple options to maintain and grow production including low cost Recompletions ("RCPs"), Workovers ("WOs") and drilling new infill wells onshore
- Successfully drilled and completed six new onshore wells in H2 2019 – including the Group's first High Angle Well ("HAW")
- Supervisory Control And Data Acquisition ("SCADA") production optimisation programme commenced Onshore, with a focus on the automation of wells and operations to reduce downtime and improve productivity
- With increased activity levels in H2 2019 quarter on quarter production volumes grew 14% to 3,196 bopd for Q4 2019 (Q3 2019: 2,816 bopd) with a robust 2019 exit production rate c. 3,400 bopd

Corporate Highlights

- Strategy of maintaining robust cash balances, a low and reducing operating break-even, plus hedging initiatives and continual drives for efficiency has placed Trinity in a strong position to endure the challenging macro-environment
- Complimenting Trinity's commitment to delivering its production and financial targets safely, we are actively pursuing our Environmental Social and Governance ("ESG") responsibilities
    - to ensure that our carbon footprint is reduced
    - whilst facilitating further operational efficiencies and cost savings
- Continued positive dialogue with both Heritage Petroleum Company Limited ("Heritage") (Trinity's partner) and the Ministry of Energy and Energy Industries ("MEEI") (Trinity's regulator) in moving both the TGAL field development plan, and the wider Trintes Area Development forward
- Total proved reserves ("2P") and contingent resources ("2C") of 41.07 mmstb at 31 December 2019 (2018: 43.26 mmstb) based on internal Management estimates.

Post Period Highlights

- Company prioritising bottom-line free cash generation and maintaining a strong balance sheet
- Production volumes over Q1 2020 averaged 3,291 bopd (a 9% year-on-year increase)
- Cash balance of USD 14.2 million (unaudited) as at 31 March 2020 reflects cash outflows for Q4 2019 taxes (including SPT) of c. USD 1.9 million, as well as annual payments (such as insurance) and Capex of c. USD 2.2 million. Average realisation of USD 46.3/bbl for Q1 means that no SPT will be payable in respect of Q1 production
- Trinity responded rapidly and comprehensively to the unprecedented human and operational consequences of the COVID-19 pandemic with Work From Home ("WFH") arrangements for office staff effective from 13 March 2020
- The Company's field operations have not, to date, been negatively impacted from COVID-19, but we continue to monitor the evolving situation and will put further appropriate measures in place as and when required
- Continued reduction in operating breakeven - targeting an average operating break-even (inclusive of hedging income) of USD 20.5/bbl for FY 2020. Actions already taken to reduce Production Costs ("Opex") and General & Administrative ("G&A") expenditure, with further measures currently under consideration
- In addition, by only incurring essential Capex spend, the Group is confident it can maintain sufficient liquidity and cash through 2020 and H1 2021 in a protracted period of low realisations
- Hedging in place provides the Group with a degree of protection against a sustained period of lower oil prices
    - 47,500 bbls/month for the first six months of 2020 (equating to approximately 46% of its 2019 exit production) and 28,333 bbls/month for the second six months of 2020 (equating to approximately 28% of its 2019 exit production)
    - USD 6.0 received for each hedged barrel for each month when WTI averages below USD 50.0/bbl
    - Hedge income in Q1 2020 totalled USD 0.5 million
- Production volumes for the remainder of 2020 will depend on oil prices and general market conditions supporting the economic case for the resumption of new drilling activity. However, even if prevailing oil prices do not support the case for a resumption of drilling in the near term, net average production for 2020 is still expected to increase to between 3,100 - 3,300 bopd (2019: 3,007 bopd)

2019 saw Trinity successfully drill and complete six new onshore wells in H2 2019. Results were encouraging and supported the delivery of production growth with average production volumes increasing to 3,007 bopd in 2019 (2018: 2,871 bopd). The deployment of SCADA and the drilling of our first HAW is testimony to our continual drive to get more for less and further enhance the business's operational resilience. As we ramp up these efficiency drives, we expect to see real benefits come to fruition.

Despite oil prices being slightly weaker during 2019 the Group reported another year of growth in operating profitability and an increase in cash balances. The upshot is that we have a robust business with an operating break-even of USD 26.4/bbl (2018: USD 29.0/bbl). This provides a natural hedge against lower oil price environments and a strong base to build upon. Based on the current oil price environment, we have refined our business model to further lower our operating break-evens and provide further resilience to a sustained period of lower oil prices.

Our performance is not only measured in financial and operational terms, but we now also measure our business outputs in terms of our environmental and social performance. During 2019 we have strengthened our commitment to minimising our carbon footprint, benefiting the environment we work in and helping to ensure the future success of the business.

Looking ahead, we are well placed to continue to grow organically but we are also positioned to make the most of other development opportunities that may arise locally. Our toolbox of skills and procedures provides us with the means to preserve as well as grow and the resilience of our business model means we face the future with cautious optimism. We expect a return to growth once we move on from the tragedies and fall out of COVID-19 and oil prices begin to recover. In the meantime, we are committed to preserving and delivering value for all our stakeholders and with our robust finances and local, highly efficient model, we are ideally positioned to take advantage of opportunities that may arise.

Bruce Dingwall CBE, Executive Chairman of Trinity, commented:
"2019 was a significant year for Trinity as we adopted new operating practices, along with new technologies and techniques, with a view to better securing, and then growing, our base production levels. The aim is to protect against the downside, whilst yielding better and more repeatable returns on investment in the future. We made substantive progress in 2019 towards our goal of becoming a more technologically driven operator in our effort to drive optimum financial and environmental performance, and these efforts will stand the Company in good stead when we look forward to 2021 and beyond.

The dedication, hard work and expertise to deliver continued growth from our portfolio of wells - 284 of which were active at the end of 2019 (2018: 216) - across nine licences and multiple reservoirs - has required a huge effort from those involved. The professionalism and resilience of our employees, and of the supply chain that supports our business, has continued to deliver uninterrupted operations so far this year despite the turbulent backdrop.

"Clearly the market has suffered due to the impact of the COVID-19 pandemic and the OPEC+ standoff, which together precipitated a significant decline in oil prices. Whilst the market backdrop is not as we would like, the strength of our operations and our balance sheet ensure that we remain well placed despite the challenging environment. We continue to prudently manage our operations, remain highly resilient to low oil prices and confident we can ride out the storm and be open to capture the opportunities that will inevitably exist for the more robust and low cost operators."

Analyst Briefing:
A briefing for Analysts will be held at 11.00 AM today via web conference. Analysts wishing to join should contact trinityexploration@walbrookpr.com for details.

Investor Presentation:
The Company will be hosting a presentation through the digital platform Investor Meet Company at 17.30 (BST) this afternoon. Investors can sign up to Investor Meet Company for free and add to meet Trinity Exploration via the following link https://investormeetcompany.com/trinity-exploration-production-plc/register-investor?arc=67fadd57-d5fe-4c5b-bf17-22467883feaa.

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About Trinity

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 2019 was 20.9 mmbbls. Group 2C contingent resources are estimated to be 20.1 mmbbls. The Group's overall 2P plus 2C volumes are therefore 41.1 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 the Alternative Investment Market ("AIM"). To achieve this, our strategy is simple: to retain the integrity of the core producing proved 2P reserves base, to continue to grow production safely, to efficiently deliver profitable operating returns and to prudently convert our significant 2C resources to 2P reserves and future inventory.

In delivering on our strategy, it is critical to ensure that we maintain both the quality of our asset base and our capability to monetise it. The successful execution of our strategy will deliver sustainable cash generation throughout reasonable oil price cycles and preserve and optimise value for shareholders in the short, medium and longer term.

The execution of our business plan during 2019 has ensured that we are strategically well positioned to continue monetising our assets (41.07 mmbbls of 2P reserves & 2C resources with exit production c. 3,400 bopd) whilst maintaining financial strength and flexibility with USD 13.8 million in cash balances (USD 17.3 million in cash plus working capital surplus) at 31 December 2019 and with the ability to focus on growth opportunities at a time when the oil and gas landscape in T&T remains subject to reform and is evolving quickly.

Operational Highlights

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 and drive improved operational profitability. 2019 saw Trinity successfully drill 6 new onshore wells in H2 2019, with encouraging results. Equally importantly, however, 2019 saw us deploy new approaches and technologies with our first Onshore HAW as the first step to deploying full horizontal wells and the trial and roll out of SCADA platforms on wells. Average production volumes grew by 5% to 3,007 bopd in 2019 (2018: 2,871 bopd). With the increased activity levels in H2 2019 there was a 14% quarter on quarter increase in average production volumes to 3,196 bopd for Q4 2019 (Q3 2019: 2,816 bopd) with exit production for 2019 of c. 3,400 bopd. The increase in annualised production was underpinned by a combination of the six new onshore development wells coming on stream during H2 2019, an increase in active offshore wells producing from 31 to 34 and the continuation of the Group's low-cost ongoing work programme of RCPs, WOs, reactivations and swabbing. The 2019 work programme included a total of 23 RCPs (2018: 17) and 122 WOs and well reactivations (2018: 143).

Financial Performance

The resulting production growth had a positive impact on our revenues in 2019 despite lower crude oil prices. Crucially, despite lower realisations, we yet again increased operating profitability with Adjusted EBITDA up 14% to USD 21.8 million (2018: USD 19.2 million) which represents an Adjusted EBITDA margin of 34% (2018: 31%). The upshot is a robust business with an operating break-even of USD 26.4/bbl (2018: USD 29.0/bbl) which provides a natural hedge against lower oil price environments and a strong base to build upon. Based on the current oil price environment, we have refined our business model to further lower our operating break-evens and provide further resilience to a sustained period of lower oil prices.

The like for like comparison of Adjusted EBITDA after SPT & PT was USD 13.9 million (USD 12.6/bbl) for 2019, a 9% increase vs. USD 12.8 million (USD 12.2/bbl) for 2018. Adjusted EBITDA after taxes, on a per share basis, was down 6% to US 3.4 cents per share (diluted) (2018: 3.6 cents) on account of the increased weighted average share count in FY 2019.

Operating Cash Flow ("OCF") for 2019 increased by 9% to USD 13.1 million from USD 12.1 million in 2018. Net OCF, after changes in working capital movements and income taxes, was USD 16.8 million (2018: USD 5.2 million). The increase is mainly due to USD 11.6 million year-on-year working capital movement compared to the previous year, which was largely attributable to the receivables due from Petrotrin being paid in 2019 rather than 2018. Stripping out the increase in receivables, the like for like OCF after changes in working capital would have been USD 10.6 million vs USD 11.8 million for 2018, primarily due to increased Value Added Tax ("VAT") recoverables and higher inventory balances at the 2019 year end.

The Group's cash balances at year end stood at USD 13.8 million (2018: USD 10.2 million). The higher cash balance is as a result of a strong operating performance and movement in working capital balances more than offsetting Capex of USD 12.7 million (2018: USD 12.5 million). In aggregate, the resultant net current assets (net cash plus working capital surplus) stood at USD 17.3 million (2018: USD 18.1 million). This financial strength and flexibility was further enhanced during the year by putting in place an overdraft credit facility, payable upon demand, with CIBC for USD 2.7 million which was undrawn at the year end.

In 2019, the impact of higher production levels and more wide-scale deployment of SCADA and other technological efficiency drives started to become apparent, enabling Trinity's low operating break-even, now well established, to continue to be reduced (2018: USD 29.0/bbl, 2019: USD 26.4/bbl). The Group has evolved its operating and financial systems and processes over the last four years to enable the business to be sustainable in a lower oil price environment and in a world of global economic uncertainties.

ESG Focus
We measure our performance not only in terms of our financial and production delivery, but also in terms of our environmental and social performance. We are committed to continue to operate all of our assets in a safe and responsible manner, to ensure the safety of employees and to minimise the potential risk to the environment. During 2019, we continued to prioritise the Health Safety Security & Environment ("HSSE") and the well-being of our people while promoting safe behaviours among all stakeholders.

Complementing Trinity's commitment to delivering its production targets safely, we are assiduously pursuing our ESG responsibilities to ensure that our carbon footprint is reduced. Trinity has established its baseline for emissions since 2017 and will be embarking on an abatement plan during 2020 to ensure that we become a more efficient and cleaner business. Specific work plans in place include the development of waste inventories and established targets to reduce, reuse and recycle waste streams across the Group; progression of the Green House Gases ("GHG") Emissions Study to develop our understanding of our total emissions and subsequent targets and strategy to reduce GHG; the identification of potential impact categories which include Workplace, Industrial, Community and Environmental and the beneficial impact of the increased usage of technology.

Maximising Low Cost Production
The financial hedging supports our effective operational hedging strategy, centred on preserving base production and retaining flexibility with multiple options to sustain and grow production including low cost RCPs, WOs and drilling new infill wells onshore. To facilitate this we have created an enhanced operational management system that builds repeatability and scalability as we grow while simultaneously driving further efficiencies in terms of well uptime resulting in reduced WOs and the better allocation of human resources.

We are geared towards further reducing cost structures and optimising production following better than expected results from the initial two well trial of Weatherford's SCADA platforms with SCADA currently in place on six wells with further roll out anticipated during 2020. This is the first time this technology has been deployed in our Onshore fields in T&T and provides a low-cost means of protecting and enhancing base production levels with the full production benefits and operating cost savings expected to become more apparent over the next one to two years.

More efficient conventional vertical wells, combined with drilling more HAWs, is aimed towards increasing IP rates, well economics and ultimately cash returns. By becoming more data driven, we have a vision to digitise the business so that we can develop analytics for our 1000+ wells (across various reservoirs which have been producing for decades) and by applying a clinical approach to increasing recovery factors and maximising reserves extraction, we are further securing the business for the future.

Growing Reserves and Resources
Trinity is well placed with a full cycle portfolio of production, development, appraisal and exploration potential.

Trinity is in the opportune position of having gone through an exploration phase in the relatively recent past which yielded the successful TGAL discovery offshore on the east coast of T&T, with the TGAL-1 exploration well drilled in very close proximity (1200m) to our producing Trintes Field. There does, however, remain further exciting low risk infrastructure led exploration and appraisal potential within our offshore east coast acreage with a total Stock Tank Oil Initially In Place ("STOIIP") of c. 700 mmstb. Trinity continues to have positive dialogue with both Heritage (Trinity's partner) and the Ministry of Energy and Energy Industries ("MEEI") (T&T's oil and gas regulator) in moving forward with the TGAL Field Development Plan ("FDP") and the wider Trintes area development. The Environmental Impact Assessment ("EIA") study commenced in February 2020. This is a pre-requisite of, and on the critical path to, allowing the Group to progress the development to Final Investment Decision ("FID") when market conditions improve.

In addition, the acquisition of a 3D seismic data package over our Onshore acreage is currently pending. We are very keen to start the interpretation and analysis of this data to yield more optimum drilling locations, facilitating fully horizontal drilling, and also to identify the exploration potential of our blocks.

The Management's 2019 estimate of the Group's total 2P reserves (Onshore and Offshore) was 20.94 mmstb (2018: 24.49 mmstb), the reduction comprising total production of 1.10 mmstb and net revisions of 2.45 mmstb. This revision is largely a function of applying a more conservative oil price deck (assuming a price towards the lower end of the SPT paying range applies throughout the forecast) and reducing the number of potential infill development wells on the East Coast assets. For the third year running, more Onshore reserves were added, as the Subsurface Team continues to add locations to the Onshore drilling inventory.

Management's 2019 estimate of the Group's contingent 2C resources was 20.13 mmstb (2018: 18.77 mmstb), with the increase primarily reflecting the re-categorisation of some East Coast asset development drilling locations to 2C (previously carried as 2P in 2018) and the reallocation of TGAL shallow (G, H and M sands) resources to 2C (previously carried as 3C in 2018) with formal development solutions being finalised. This follows the high grading of a first phase development stage of the deeper TGAL reservoirs, as per the submitted FDP, targeting 10.41 mmstb (net) with more robust overall economics. These high graded 2C resources would be expected to convert to 2P following FID.

In aggregate, therefore, total 2P reserves and 2C resources amounted to 41.07 mmstb at 31 December 2019 (2018: 43.26 mmstb). So whilst we do have exploration potential across our portfolio, a clear growth trajectory is already in place with substantial existing reserves and resources to be monetised.

2020 and Beyond

Our principal priority during the global pandemic is on the safety and health of our people so we have put in place a full suite of measures to achieve this including regular and updated advisories, enhanced hygiene practices and full contingency plans should any team member be exposed to the virus. In light of the first confirmed case in T&T, Trinity implemented WFH practices for all but essential field operators and these are working well. All international travel has been suspended and minimal local travel to maintain well operations in the fields is being undertaken under the strict proviso of appropriate physical distancing measures being adhered to. The Group's operations have not, to date, been negatively impacted by COVID-19 and have, by law, been classified an essential business and therefore able to continue operations. We will continue to monitor the evolving situation and put further appropriate measures in place as and when required.

This time last year, our aim was to build on our stable base production, add well inventory and execute an investment programme that included technological step-outs whilst maintaining controls on operating costs and HSSE. The Group managed to deliver on that initial programme, resulting in continued improvement in our operational performance and KPIs. We are well placed to continue to grow organically but also positioned to make the most of other development opportunities that may arise. We are assured that our locally led business model is well suited to the future based on our strong relationships with Heritage and with other partners on the ground in T&T.

KEY PERFORMANCE INDICATORS

The Group was profitable at an operating level throughout 2019 with a 14% increase in Adjusted EBITDA to USD 21.8 million (2018: USD 19.2 million), a year-end cash balance of USD 13.8 million (2018: USD 10.2 million) and net current assets of USD 17.3 million (2018: USD 18.1 million). A summary of the year-on-year operational and financial highlights are set out below:

		FY 2019	**FY 2018**	**Change %**
Average realised oil price[1]	*USD/bbl*	58.1	59.8	(3)
Average net production	*bopd*	3,007	2,871	5
Annual production[2]	*mmbbls*	1.10	1.05	5
Revenues	*USD million*	63.9	62.6	2
Operating Expenses	*USD million*	53.6	55.9	(4)
Operating Profit before SPT & PT	*USD million*	10.3	6.7	54
Adjusted EBITDA[3]	*USD million*	21.8	19.2	14
Adjusted EBITDA[4]	*USD/bbl*	19.8	18.3	9
Adjusted EBITDA margin[5]	*%*	34	31	11
Adjusted EBITDA Per Share - Diluted[6]	*US cents*	5.3	5.4	(2)
Adjusted EBITDA after SPT & PT[7]	*USD million*	13.9	12.8	9
Adjusted EBITDA after SPT & PT[8]	*USD/bbl*	12.6	12.2	4
Adjusted EBITDA after SPT & PT Per Share - Diluted[9]	*US cents*	3.4	3.6	(6)
Consolidated operating break-even[10]	*USD/bbl*	26.4	29.0	(9)
Cash balance	*USD million*	13.8	10.2	35
Net cash plus working capital surplus[11]	*USD million*	17.3	18.1	(4)

Notes:
1. *Realised price: Actual price received for crude oil sales per barrel (“bbl”).*
2. *Annual production (mmbbls) — Production sold in a given year*
3. *Adjusted EBITDA (USD million): Operating Profit before Taxes for the period, adjusted for DD&A, non-cash SOE, ILFA and hedge costs*
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 & PT (USD million): Adjusted EBITDA after SPT & PT.*
8. *Adjusted EBITDA after SPT & PT (USD/bbl): Adjusted EBITDA after SPT & PT / Annual production.*
9. *Adjusted EBITDA after SPT & PT per Share — Diluted: Adjusted EBITDA after SPT & 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. *Net cash plus working capital surplus: Current Assets less Current Liabilities (other than Provisions for other liabilities).*

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 by Management to assess the Group's growth and underlying operational and financial performance.

	2019	**2018**
	USD million	*USD million*
Operating Profit before SPT & PT	10.3	6.7
DD&A	9.8	10.7
SOE	1.0	0.7
ILFA	0.6	-
FX loss/(gain)	0.1	(0.0)
Other Expenses (Hedge Costs)	0.1	1.1
Adjusted EBITDA	**21.8**	**19.2**
Less: SPT & PT	(7.9)	(6.4)
Adjusted EBITDA after SPT & PT	**13.9**	**12.8**
Expressed in US cents		
Adjusted EBITDA Per Share - diluted	*5.3*	*5.4*
Adjusted EBITDA after SPT & PT per Share - diluted	*3.4*	*3.6*

See Note 23 to Consolidated Financial Statements – Adjusted EBITDA

2019 Trading Summary

A 5-year historical summary of realised price, production, operating break-even, Opex and G&A expenditure metrics is set out below:

Details		**2015**	**2016**	**2017**	**2018**	**2019**
Realised Price	*USD/bbl*	**45.5**	**39.4**	**48.6**	**59.8**	**58.1**
Production						
Onshore	*bopd*	1,601	1,343	1,347	1,563	1,616
West Coast	*bopd*	312	190	212	198	185
East Coast	*bopd*	983	1,009	961	1,110	1,208
Consolidated	*bopd*	2,896	2,542	2,519	2,871	3,007

Operating Break-Even[1]		**2015**	**2016**	**2017**	**2018**	**2019**[4]	**2019**[5]	**IFRS 16 Impact**
Onshore	*USD/bbl*	23.3	17.4	16.6	16.1	16.4	16.6	(0.3)
West Coast	*USD/bbl*	40.7	37.7	26.6	26.8	32.4	32.9	(0.4)
East Coast	*USD/bbl*	41.3	26.3	24.9	25.9	21.9	22.1	(0.2)
Consolidated[2]	*USD/bbl*	47.2	29.2	28.4	29.0	26.4	26.8	(0.4)
Metrics								
Opex/bbl - Onshore	*USD/bbl*	15.7	11.8	11.1	11.7	12.1	12.3	0.2
Opex/bbl - West Coast	*USD/bbl*	33.8	31.6	22.1	22.1	26.9	27.2	0.4
Opex/bbl - East Coast	*USD/bbl*	31.6	20.1	18.9	20.1	17.1	17.3	0.2
G&A/bbl – Consolidated[3]	*USD/bbl*	9.6	4.4	4.4	5.0	5.1	5.2	0.1

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 SOE and FX gain/loss.

3. G&A/bbl – Consolidated: Excludes SOE and FX gain/loss.

4. Metrics post IFRS 16 adoption effective 1 January 2019 which impacted the Operating Break-Even Levels and Opex/bbl & G&A/bbl Metrics

5. Metrics pre-IFRS 16 adoption effective 1 January 2019 which impacted the Operating Break-Even Levels and Opex/bbl & G&A/bbl Metrics

2019 was a significant year as production averaged over 3,000 bopd for the first time in five years with the benefits of the drilling of new development wells during 2018 and 2019. Of particular note from a financial standpoint is that operating break-evens were reduced with an aggregate of 9% to USD 26.4/bbl (2018: USD 29.0/bbl). The consolidated operating break-even includes the Group's cash G&A costs and therefore captures the corporate costs associated with supporting the asset base.

At the corporate level, the maintenance of such a robust operating level break-even level reflects higher production volumes and lower combined expenses as detailed below:

- Overall Opex decreased by 8% to USD 16.4 million (2018: 17.8 million). This was largely a function of a lower WO programme, production optimisation and better well uptimes, re-negotiated terms of the supply/personnel vessels and port rental and a partial reduction based on the adoption of the new leases standard IFRS 16.
- G&A costs (which exclude non-cash SOE and FX gain/loss) increased by 8% to USD 5.6 million (2018: USD 5.2 million). This is in relation to increased staff costs, levies and corporate expenses.

OPERATIONAL REVIEW

Our People
Trinity's workforce stood at 214 (2018: 215) at the year-end December 2019 with 78% (166) male and 22% (48) 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.

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

The Board is fully apprised of the Group's HSSE performance via updates at each Board meeting and from 2020 onwards this will be done on a monthly basis. The HSSE report is considered at each Board meeting and is usually the first matter considered on meeting agendas.

Management's commitment to behaviour based HSSE programmes - of which the See, Think, Act, Reinforce and Track ("START") Card programme is an example - has positively impacted our HSSE culture. During 2019, we have noted an 84% increase in participation by all employees in our START Card programme. Trinity also introduced a new initiative to report on the closure rate of all items identified in the START Card programme and routinely informed the frontline employees on their participation to further enhance their performance.

Training hours recorded also saw an increase of 24% to 3,364 hours from 2,718 hours as safety remained as a top priority to Trinity to ensure that employees are competent and confident to execute all tasks in a safe and efficient manner.

Trinity recorded 844,074-man hours in 2019 (2018: 643,400 man hours), a 31% increase, mainly due to the 2019 work programme which included onshore drilling as well as onshore and offshore RCPs and WOs. Notable improvements in our HSSE reporting were achieved due to our continued emphasis on a strong HSSE culture, facilitated by an increase in Management visits to all assets, increased feedback on lessons learned and multiple proactive initiatives implemented across all operations.

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 ("ECTT"). 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. The internal audit process for the planned recertification inspection in Q1 2020 was completed in Q3 2019. However, due to the COVID-19 pandemic, the ECTT has deferred all audits for a 3 month period effective 1 March 2020 and so Trinity is now expected to be undergoing recertification at a later date in 2020. Notwithstanding our 2019 achievements, in 2020 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 with the goal of becoming SO 45001:2018 compliant by Q2 2021.

Production
Average net production for 2019 was 3,007 bopd (2018: 2,871 bopd), an increase of 5%. A total of six new infill development wells, 23 RCPs, 122 WOs and reactivations along with swabbing activities were undertaken during 2019.

Trinity has been constantly striving towards establishing our base production at a higher level. This requires continuous improvements of our operations via the standardisation of procedures, innovative approaches in addressing emerging challenges and the application of new technologies to improve performance, reliability and efficiencies. 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 2019 net production from the Onshore assets was 1,613 bopd (3% increase from 2018 (1,563 bopd)), which accounted for 54% of total annual average production. The growth in year-on-year production averages is reflective of successfully maintaining base production and the impact of new infill development wells which were drilled during H2 and the full impact Q4 in particular (with absolute production growth higher than the annual average).

The drilling programme for 2019, which was completed on time and on budget, consisted of six Onshore wells and delivered:

1) an increase of 20% in EUR reserves above pre-drill prognosis (0.60 mmbbls vs 0.50 mmbbls)
2) an increase of 47% in estimated Net Oil Sand ("NOS") encountered over pre-drill prognosis (1653' vs 1125')

3) an increase of 54% in IP's over pre-drill prognosis (cumulative 650 bopd vs 421 bopd)

The strong performance of the 2019 drilling campaign was due to a more robust approach to sub-surface mapping and a more rigorous examination of reservoir performance which enabled more precise risking and ranking of potential reservoir targets. The drilling programme lasted 125 days and there were no Lost Time Accidents ("LTAs") over the period, a significant achievement by the drilling team and lead contractors.

The drilling programme included our first HAW, FR 1807, which has continued to perform satisfactorily:

1) The well had a peak production rate of over 110 bopd vs the 50 bopd typically expected from a conventional vertical well
2) It attained a maximum daily production rate of 118 bopd prior to the planned implementation of a gravel pack, a completion technique to arrest sand production
3) Diagnostic and remediation strategy to obtain improved production is underway

Trinity executed 22 RCPs Onshore for the period (2018: 16) as well as Onshore WOs and reactivations on 104 wells (2018: 113). This intensive work campaign successfully maintained base production providing a stable platform for production growth.

Going forward, dependent on the prevailing macro environment, the Group intends to continue with development activities via additional infill development drilling (particularly of additional HAWs), the restocking of RCPs, WOs, and reactivations and swabbing on the current well stock to maintain our production and provide for further growth.

East Coast Assets

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

Average 2019 net production from the East Coast was 1,205 bopd which accounted for 40% of total annual average production. This represented a 9% increase in production from the 2018 average net production levels of 1,110 bopd. The increase was largely as a result of (i) improved power reliability, (ii) the successful execution of a just in time WO campaign that included the reactivation of four wells and continuous well optimisation.

In 2019, 13 restorative WOs were completed (2018: 23) which contributed to an upward trend in production. In 2019, production was derived from 34 of a possible 61 wellbores in the Trintes Field. The Trintes Field produces via numerous pumping technologies across our well stock including Mechanical Pumping Hydraulic Unit ("MPHU"), Hydraulic Diaphragm Electric Submersible Pump ("HDESP"), Electric Submersible Pump ("ESP") and Progressive 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 designs to overcome challenging wellbore conditions.

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.

Infrastructure investment during 2019 included the completion of significant structural upgrades without the need for any shut-ins with production sustained throughout. Essential investment to ensure structural integrity across the platforms will continue in 2020. Continued investment to increasing storage capacity will also take place with the construction of a new 10,000 barrel tank.

West Coast Assets

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

Average 2019 net production from the West Coast was 189 bopd which accounted for 6% of total annual average production. This represented a 5% decrease in production from 2018 average levels of 198 bopd and was mainly attributed to natural production decline.

There were 4 WO's (2018: 3) in the PGB field and 1 WO (2018:4) on the land-based wells in the Brighton Field which were undertaken with the intention of arresting declines and stabilising base production levels. Swabbing operations on the Brighton Marine offshore facilities commenced in Q4 adding an additional 17 bopd and chemical injection has allowed for stabilisation of production through the delay of wax formation in the wells. Minor infrastructural works were undertaken on the offshore platforms to maintain asset integrity and production.

These assets continue to generate a 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 relatively low cost.

Reserves and Resources

A comprehensive management review of all assets has been concluded and has estimated the current 2P reserves to be 20.97 mmstb at the end of 2019, compared to the year-end 2018 reserve estimate of 24.49 mmstb. This represents a 14% decrease of 3.55 mmstb from 2018 levels inclusive of production for 2019 of 1.10 mmstb (2018: 1.09 mmstb). The reduction in reserves predominantly reflects the application of an oil price forward curve which was towards the lower end of the SPT payable range, as well as updated well numbers and decline curve analysis on producing wells offshore the East Coast.

Onshore 2P reserves grew by 2% as a result of our ongoing continued investment in subsurface analysis to generate additional infill drilling, RCP and WO candidates. This follows on from a 26% increase delivered in 2018 and 45% in 2017. Management considers this to be the best estimate as at 31 December 2019 of the quantity of reserves that will actually be recovered from the assets. 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 following table:

Unaudited 2019 2P Reserves

Asset	**31 December 2018**	**Production**	**Revisions**	**31 December 2019**
Net Oil Production	*mmstb*	*mmstb*	*mmstb*	*mmstb*
Onshore	7.30	(0.59)	0.72	7.43
East Coast*	14.80	(0.44)	(3.09)	11.27
West Coast	2.39	(0.07)	(0.08)	2.24
Total	**24.49**	**(1.10)**	**(2.45)**	**20.94**

Note(*):

i. *East Coast 2P resource change primarily reflects moving 2 wells to contingent resources and changes to certain infill well decline profiles. Trinity has further risked the production profiles to reflect reservoir performance from more recent drills, RCPs and WOs which results in a more cautious assessment of initial flow rates, production profile declines and, ultimately, lower EUR.*

ii. *Changes to economic limit testing for the asset YE 2019 vs YE 2018 also impact the Trintes 2P position; the YE 2018 oil price deck used did not trigger SPT whereas that used in YE 2019 triggers SPT over the life of the Trintes asset.*

The best estimate of 2C resources is estimated by Management at 20.13 mmstb (2018: 18.77 mmstb). The positive movement of 1.36 mmstb in 2C resources primarily reflects the re-categorisation of some infill development drilling locations to 2C (previously carried as 2P in 2018) and the reallocation of TGAL shallow (G, H and M reservoirs) resources to 2C (previously carried as 3C in 2018).

Unaudited 2019 2C Resources

	31 December 2018	**Revisions**	**31 December 2019**
Asset	*mmstb*	*mmstb*	*mmstb*
Onshore	1.50	0.35	1.85
East Coast	16.38	0.90	17.28
West Coast	0.89	0.11	1.00
Total	**18.77**	**1.36**	**20.13**

Unaudited Summary of Reserves and Resources at 31 December 2019

	2P Reserves	**2C Resources**	**2P Reserves and 2C Resources**
Asset	*mmstb*	*mmstb*	*mmstb*
Onshore	7.43	1.85	9.28
East Coast	11.27	17.28	28.55
West Coast	2.24	1.00	3.24
Total	**20.94**	**20.13**	**41.07**

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 STOIIP of over 700 mmstb of which only 249 mmstb of STOIIP is mapped against the Trintes Field. Trintes currently booked East Coast 2P reserves of 11.27 mmstb therefore represents an incremental recovery factor of 4.5%, with a further 2.77 mmstb (or 1.1%) booked within contingent resources.

Galeota (TGAL) Field Development Plan (Trinity: 65% WI)

The TGAL area lies in the Galeota Licence and is Fault Block 6, an up-dip panel to the north east of Trintes, confirmed as being oil bearing in all major reservoir horizons by the TGAL-1 exploration well with an internal best estimate STOIIP of 186 mmstb. The FDP (submitted in November 2018) describes the first phase of a potential wider development across the Galeota anticline to fully develop the reserves potential from the large volumes of oil in place.

Some of the highlights of the proposed Fault Block 6 Development include:

- An unmanned platform with minimal top-side design ("Platform Echo")
- 25-year design life
- Drilling with the use of a jack-up rig
- A new pipeline from Platform Echo to shore
- Subsea power cable from shore to Platform Echo
- First oil estimated being produced by H1 2022, subject to prevailing market conditions, and peak production estimated at 5,800 bopd
- 2C resources of up to c.24.18 mmstb gross (14.51 mmstb net). The net 2C figure is inclusive of 10.41mmstb being developed by the new platform, and 4.1mmstb for the shallow resources that, after review, have moved back into 2C (was re-categorised YE 2018 from 2C to 3C)
- At Final Investment Decision ("FID") Trinity anticipates the net 2C resources developed by the Platform Echo solution would be reclassified as 2P reserves

During 2019 works progressed (and are continuing) on various pre-FEED studies to improve the topside and other aspects of the hardware design. Of equal importance, the environmental permitting process was advanced with submission of the application and all additional information requested by the Environmental Management Authority of Trinidad and Tobago ("EMA") during 2019. The Environmental Impact Assessment ("EIA"), which is a key item on the critical path to FID, is currently underway.

FINANCIAL REVIEW

Trinity and its subsidiaries ("the Group's") consolidated financial information has been prepared on a going concern basis, in accordance with International Financial Reporting Standards ("IFRS") Interpretations Committee ("IFRS IC") interpretations as adopted by the European Union ("EU") and those parts of the Companies Act ("CA") 2006 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 1 of the Financial Statements. The Group has adopted additional accounting policies in the year ended 31 December 2019 as set out in the notes to Financial Statements.

Throughout this report reference is made to adjusted results and measures. The Board 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 underlying cash earnings achieved in the year. In exercising this judgment, the Board 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 impact of SOE, ILFA and oil price hedges and these are summarised on the face of the Consolidated Income Statement as well as being described in the notes to the financial statements.

Results for the year

- **Revenue growth from increased production despite lower oil price realisations:** The combination of a 5% increase in production to 3,007 bopd (2018: 2,871 bopd) and a 3% decrease in average oil price realisations to USD 58.1/bbl (2018: USD 59.8/bbl) resulted in a 2% increase in revenues to USD 63.9 million (2018: USD 62.6 million).
- **Successful Capex work programme:** USD 12.7 million (2018: USD 12.5 million) incurred in predominantly production related and infrastructure expenditure. 2019 saw the Group complete 6 Onshore development wells, 22 Onshore RCP's and the second RCP on the East Coast since acquiring the asset in 2013. Infrastructure Capex were also conducted across the assets to support the production initiatives. Capex included:
- USD 7.4 million New Wells (6 wells, of which 1 HAW and 5 conventional)
- USD 2.8 million Infrastructure Capex
- USD 1.3 million 23 RCP's
- USD 0.6 million Subsurface time-writing costs
- USD 0.6 million Exploration and Evaluation ("E&E") assets
- **Further growth in operating margins and increased operating profitability:** The Group maintained its focus on growing margins and increasing operating profitability which is evident in a 14% increase in Adjusted EBITDA to USD 21.8 million (2018: USD 19.2 million) and 9% lower consolidated operating break-even price of USD 26.4/bbl (2018: USD 29.0/bbl), while increasing Adjusted EBITDA Margin to 34% in 2019 (2018: 31%). On a per barrel basis this represents an 8% increase in Adjusted EBITDA to USD 19.8/bbl (2018: USD 18.3/bbl) and a 2% decrease in Adjusted EBITDA per share (diluted) to 5.3 cents (2018: 5.4 cents) due to the increased average share count.
- **SPT & PT:** 2019 and 2018 saw average oil price realisations above USD 50.0/bbl, thereby being in the SPT paying range. As a result, SPT of USD 7.4 million was incurred in 2019 (2018: USD 7.1 million).
- **Impairment losses (non-cash):** during the year the Group recorded property, plant and equipment impairment losses on its oil and gas assets of USD 15.2 million (2018: USD 2.6 million) within exceptional items. The carrying values of certain of the Group's cash generating units were deemed to be higher than their recoverable amount measured utilising a discounted cash flow approach to fair value less cost of disposal. This was largely driven by the application of a more conservative oil price forward curve at 31 December 2019, on account of it falling towards the lower end of the SPT payment range. The Group also recognised USD 0.6 million (2018: nil) of impairment losses on carrying values held within trade and other receivables due to expected credit loss following the adoption of IFRS 9 financial instruments.
- **Increased Operating Cash Flows:** OCF for 2019 increased by 9% to USD 13.1 million (2018: USD 12.1 million). Net OCF, after changes in working capital movements and income taxes, was USD 16.8 million (2018: USD 5.2 million). The increase is mainly a function of a USD 11.6 million year-on-year working capital movement from the prior year, which was largely attributable to the receivables due from Petrotrin being paid in 2019 rather than 2018. Stripping out the increase in receivables, the like-for-like OCF after changes in working capital would have been USD 10.6 million vs. USD 11.8 million for 2018. Decreases in working capital were attributed to lower trade and other payables by USD (1.0) million and increased inventory of USD (1.5) million and increased VAT receipts due (USD 2.9 million vs 2018: USD 1.6 million).
- **Increased Financial Strength:** The Group's cash balances at year end stood at USD 13.8 million (2018: USD 10.2 million). The higher cash balance is as a result of a strong operating performance and movement in working capital balances more than offsetting Capex of USD 12.7 million (2018: USD 12.5 million). In aggregate, the resultant net cash plus working capital surplus stood at USD 17.3 million (2018: USD 18.1 million). This financial strength and flexibility was further enhanced during the year by putting in place an overdraft credit facility with CIBC for USD 2.7 million which was undrawn at the 2019 year end.

Revenues

Crude oil sales revenues of USD 63.9 million (2018: USD 62.6 million).

Operating expenses

Operating expenses decreased by 4% in 2019 to USD (53.6) million (2018: USD (56.7) million) and comprised:

- Cash Expenses: USD (42.1) million (2018: (45.3) million):
  - Royalties of USD (20.0) million (2018: USD (20.4) million) have decreased due to the new wells from the 2018 and 2019 drilling campaign attracting 0%-10% ORR.
  - Opex of USD (16.4) million (2018: USD (17.8) million) have decreased due to lower costs in relation to WOs, production optimisation and vessel and equipment.
  - G&A expense of USD (5.6) million (2018: USD (5.2) million) have increased due to an increase in staff and corporate costs.
  - Other expenses of USD (0.1) million (2018: USD (1.1) million) includes the impact of hedge costs in relation to the zero cost collar/ put options implemented during 2019.
- Non-Cash Expenses: USD (11.5) million (2018: USD (11.4) million):
  - DD&A of USD (9.8) million (2018: USD (10.7) million).
  - SOE of USD (1.0) million (2018: USD (0.7) million).
  - ILFA: USD (0.6) million (2018: nil).
  - FX (loss)/gain of USD (0.1) million (2018: USD 0.0 million).

Note (*): the relatively modest impact on Opex and G&A of the adoption of IFRS 16 for leases is set out in the following section.

SPT & PT

SPT & PT were USD (7.9) million (2018: USD (6.4) million) and comprised:

- SPT of USD (7.4) million (2018: USD (7.1) million) due to realised oil prices being above the USD 50.01/bbl SPT threshold.
- PT charge of USD (0.5) million (2018: USD 0.6 million credit). There is still no official guidance on the PT valuation method as it relates to oil and gas entities. The 2017 and prior obligations were waived during 2018 but the Group is still providing for the potential obligations arising in 2018 and 2019.

The Group's reported operating profit before exceptional items was USD 2.4 million (2018: USD 0.2 million). Adjusting for non-cash expenses, the Group's Adjusted EBITDA after SPT & PT was USD 13.9 million (2018: USD 12.8 million) (further details below).

Exceptional items

Exceptional items were USD (15.2) million (2018: USD (2.3) million) related to Impairment of property, plant and equipment

See Note 6 to Consolidated Financial Statements

Finance Income

Finance income is solely related to interest income derived on short term investments USD 0.1 million (2018: 0.1 million).

Finance Costs

In 2019, finance costs amounted to USD (1.4) million (2018: USD (2.2) million) and comprised:

- Unwinding of the decommissioning liability USD (1.2) million (2018: USD (1.6) million).
- Interest on Leases USD (0.2) million (2018: nil).
- Interest accrued on the CLNs nil (2018: (0.6) million).

See Note 7 to Consolidated Financial Statements

Income Taxation

Income Taxation credit for 2019 of USD 4.4 million (2018: USD (1.3) million charge), and its components are described below.

- Increase in DTA of USD 3.4 million based on the increase in taxable profits expected in the next three years (2018: USD 1.8 million).
- Decrease in Deferred Tax Liabilities ("DTL") USD 1.4 million as the temporary difference between the accounting values of property, plant and equipment, intangible assets and tax values decreased compared to 2018 (2018: USD (3.1) million charge).
- Increase in Unemployment Levy ("UL") USD (0.4) million (2018: USD 0.0 million credit).

See Note 8 to Consolidated Financial Statements

The Group's comprehensive post-tax loss for the period was therefore USD (9.6) million (2018: USD (5.3) million loss).

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 & PT for the period, adjusted for non-cash DD&A, SOE, ILFA, FX gain/loss and fair-valuing of oil price hedges.

The Group presents Adjusted EBITDA at USD 21.8 million and Adjusted EBITDA after SPT & PT at USD 13.9 million as it is used in by Management to assess the Group's growth and underlying operational and financial performance.

Statement of Cash Flows

Cash inflow/ (outflow) from operating activities

OCF was USD 16.8 million (2018: USD 5.2 million):

- Operating cash flow (pre-working capital movements and income tax) of USD 13.1 million (2018: 12.1 million) reflected a reported Operating Loss before income tax of USD (14.1) million (2018: USD (4.1) million) less non-cash items totalling USD 27.2 million (2018: USD 16.2 million) principally comprising DD&A, impairment of Oil & Gas asset valuations, unwinding of Decommissioning provisions and SOE.
- Changes in working capital of USD 3.9 million inflow (2018: USD 6.8 million outflow), primarily as a result of the decrease in trade receivables compared to the 2018 year end.
- Current income taxation paid USD (0.3) million outflow (2018: USD (0.1) million outflow).

Cash (outflow) from investing activities

Cash outflow from investing activities was USD (12.7) million (2018: USD (12.5) million):

- Expenditure on property, plant and equipment for the year was USD (12.1) million (2018: USD (12.3) million) which mainly included 6 onshore development wells, 23 RCPs and infrastructure upgrades.
- Expenditure on exploration and evaluation assets and computer software USD (0.6) million (2018: USD (0.2) million).

Cash (outflow)/inflow from financing activities

Cash outflow from financing activities was USD (0.4) million (2018: USD 11.5 million inflow):

- Cash payment on leases USD (0.6) million (2018: nil)
- Finance income of USD 0.1 million (2018: USD (0.1) million in Finance costs.
- Repayment of CLN nil (2018: USD (0.8 million).
- Issuance of shares nil (2018: USD 12.4 million inflow).

Net Cash Plus Working Capital Surplus

	All figures USD million	**FY 2019 USD million Audited**	**FY 2018 USD million Audited**	**FY 2017 USD million Audited**
A:	**Current Assets**			
	Cash and Cash equivalents	13.8	10.2	11.8
	Trade and other receivables	9.3	13.3	5.2
	Inventories	5.2	3.7	3.8
	Derivative Financial Instrument	0.1	-	-
	Total Current Assets	**28.4**	**27.2**	**20.8**
B:	**Current Liabilities***			
	Trade and other payables	10.4	9.1	10.1
	Lease Liability	0.6	-	-
	Taxation payable	0.1	-	1.7
	Derivative Financial Instrument	-	-	0.8
	Total Current Liabilities	**11.1**	**9.1**	**12.6**
(A-B):	**Net Cash Plus Working Capital Surplus**	**17.3**	**18.1**	**8.2**

Note (*): Current Liabilities excludes Provision for other liabilities

Adoption of IFRS 16 Leases

IFRS 16 is a new accounting standard effective 1 January 2019. This accounting standard supersedes IAS 17 Leases and results in almost all leases being recognised on the balance sheet, as the distinction between operating and finance leases is removed. Under the new standard, Right of Use Assets ("ROU") and a financial liability to pay rentals are recognised. The only exceptions are short-term (less than 12 months) and low-value leases (less than USD 5,000).

The Group has adopted IFRS 16 from 1 January 2019, but has not restated comparatives for the 2018 reporting period, as permitted under the simplified transitional approach. On transition the Group elected to apply the practical expedient to grandfather the assessment of which transactions are leases. It applied IFRS 16 only to contracts that were previously identified as leases. Contracts that were not identified as leases under IAS 17 and IFRS IC 4 were not reassessed. Therefore, the definition of a lease under IFRS 16 has been applied only to contracts entered into or changed on or after 1 January 2019.

On adoption of IFRS 16, the Group has recognised ROU assets and lease liabilities in relation to Motor vehicles, Office buildings, Staff houses and Office Equipment. The following table sets forth the impact of the adoption of IFRS 16 on the condensed consolidated financial statements as well as non-IFRS measures.

1. Impact on Consolidated Statement of Comprehensive Income

(a) Impact on Net Profit and Earnings per share:	**IFRS 16**	**IAS 17**	**Difference**
All figures USD million			
Expenses			
Opex	(16.4)	(16.8)	0.4
G&A	(5.6)	(5.7)	0.1
DD&A	(9.8)	(9.3)	(0.5)
Finance costs	(1.2)	(1.1)	(0.2)
	(33.0)	**(32.9)**	**0.1**
Total Comprehensive (Expense)/Income for the period	**(9.6)**	**(9.5)**	**0.1**
Earnings Per Share	(0.02)	(0.02)	0.00

(a) Impact on non-IFRS measures used by the Group:		**IFRS 16**	**IAS 17**	**Difference**
Opex	*USD million*	(16.4)	(16.8)	0.4
G&A	*USD million*	(5.6)	(5.7)	0.2
Total	*USD million*	**(22.0)**	**(22.5)**	**0.6**
2019 Metrics				
Opex	*USD/bbl*	14.8	15.4	(0.4)
G&A	*USD/bbl*	5.1	5.2	(0.1)
Adjusted EBITDA	*USD million*	21.8	21.2	(0.6)
Adjusted EBITDA	*USD/bbl*	19.8	19.3	(0.5)
Adjusted EBITDA After SPT & PT	*USD million*	13.8	13.3	(0.5)
Adjusted EBITDA After SPT & PT	*USD/bbl*	12.6	12.1	(0.5)
Group operating break-even	*USD/bbl*	26.4	26.8	(0.4)

2. Impact on Consolidated Statement of Financial Position

ROU and Lease Liabilities recognised in Balance Sheet:	**1-Jan-19**	**Depreciation**	**Lease Payment**	**Lease Interest**	**31-Dec-19**
All figures USD million					
ROU recognised					
Non- current assets	0.5	(0.5)	-	-	1.4
	0.5	**(0.5)**	**-**	**-**	**1.4**
Lease Liabilities recognised as at 1 January 2019					
Current lease liabilities	0.2	-	(0.6)	0.2	0.6
Non-current lease liabilities	0.3	-	-	-	0.9
	0.5	**-**	**(0.6)**	**0.2**	**1.5**

Events Since the Year End

1. **Hedging**

   The Company implemented two additional crude hedge options over the Group's monthly production on 3 January 2020 as follows:

Hedge	Floor	Cap	Strike Price	Production	Effective Date	Expiry Date
	USD/bbl	*USD/bbl*	*USD/bbl*	*Monthly Barrels*		
3-way Option	50.0	56.0	65.5	12,500	1-Jan-20	31-Dec-20
3-way Option	50.0	56.0	65.5	12,500	1-Jul-20	31-Dec-20

2. **Petrotrin Legacy Receipts**

   There remains an outstanding payment due from Petrotrin for October and November 2018 crude oil revenues, with an amount outstanding of USD 0.5 million at the end of 2019 for which an Expected Credit Losses ("ECL") of USD 0.2 million was recognised. The Group received USD 0.1 million of these delayed payments on 7 February 2020, with the remaining USD 0.4 million still outstanding.

3. **COVID-19 Pandemic and Oil Price Decline**

   The impact of the COVID-19 virus on the demand end for oil, and the inability of OPEC and Russia to agree sufficient supply curbs in a timely manner, has led to a significant decline in the oil price. WTI traded as high as USD 63.0/bbl in early January 2020, declining to USD 45.0/bbl as a result of reduced demand from COVID-19 in early March 2020, prior to the oil price war which subsequently drove prices lower than USD 20.0/bbl. On 12 April 2020, OPEC and Russia announced plans to reduce production output by nearly 10.0 mmbbls. However, concerns about storage capacity being exceeded led to oil-market history being made on 20 April 2020 when WTI prices dropped below zero for the first time (to minus USD 37.63/bbl). Although prices have since recovered somewhat, they remain below USD 30.0/bbl as at the last practicable date prior to approval of this announcement on 12 May 2020, and there remains considerable uncertainty regarding oil price levels during the remainder of 2020, and possibly beyond.

   The World Health Organisation ("WHO") officially declared COVID-19 as a pandemic on 11 March 2020. Effective 22 March 2020, the Government of the Republic of Trinidad and Tobago ("GORTT") closed T&T's borders to all international and national travelers via the air bridge and sea ports. Subsequently, the operations of only essential services were approved by the GORTT (which includes oil and gas companies within T&T).

   The COVID-19 pandemic's impact on demand for oil, the subsequent fall in oil prices, and the potential operating disruption to oil and gas companies is an extremely challenging and evolving situation. Given the fluidity and significant volatility of these events, it is extremely difficult to predict their impact on the Group at this stage as the oil price environment is dependent on the interplay between global demand and supply, both of which are changing significantly. Nevertheless, having assessed the current impact of these various factors, and the potential impact of a prolonged economic downturn triggered by the COVID-19 pandemic, the Directors currently believe the Group can maintain sufficient liquidity and a positive cash balance, and remain in operational existence, for at least the next twelve months (see Going Concern refer to Note 1 to Financial Statements).

4. **CIBC Full Overdraft Credit Facility Drawdown**

   Trinity fully drew down its USD 2.7 million overdraft credit facility with CIBC effective 2 April 2020 as part of its strategy of maximising available cash during the short-medium term. The facility is a revolving overdraft credit available to Trinity which is repayable upon demand to CIBC. Interest is required to be paid monthly on the principal and currently attracts an interest rate charge of 2.7% (US Prime minus 6.3% per annum).

Consolidated Statement of Comprehensive Income
For the year ended 31 December 2019
(Expressed in United States Dollars)

	Note	2019	2018
		$'000	**$'000**
Operating Revenues			
Crude oil sales		63,878	62,578
Other income		14	15
		63,892	62,593
Operating Expenses			
Royalties		(20,034)	(20,390)
Production costs		(16,426)	(17,754)
Depreciation, Depletion & Amortisation ("DD&A")	11-13	(9,772)	(10,694)
General & Administrative ("G&A") expenses		(5,589)	(5,240)
Impairment losses on financial assets ("ILFA")		(608)	--
Share Option Expense ("SOE")		(1,038)	(737)
Foreign exchange ("FX") (loss)/gain		(76)	17
Other Expenses		(78)	(1,075)
		(53,621)	(55,873)
Operating Profit before Supplemental Petroleum Taxes ("SPT") & Property Taxes ("PT")		**10,271**	**6,720**
SPT		(7,413)	(7,050)
PT		(492)	607
Operating Profit before Exceptional Items		**2,366**	**277**
Exceptional items	6	(15,187)	(2,312)
Operating Loss		**(12,821)**	**(2,035)**
Finance income	7	138	93
Finance costs	7	(1,372)	(2,149)
Loss Before Income Taxation		**(14,055)**	**(4,091)**
Income taxation credit/(expense)	8	4,408	(1,270)
Loss for the year		**(9,647)**	**(5,361)**
Other Comprehensive Income			
Items that may be subsequently reclassified to profit or loss			
Currency translation		85	40
Total Comprehensive Loss For The Year		**(9,562)**	**(5,321)**
Earnings per share (expressed in dollars per share)			
Basic	9	(0.02)	(0.02)
Diluted	9	(0.02)	(0.02)

Consolidated Statement of Financial Position
at 31 December 2019
(Expressed in United States Dollars)

	Note	2019	2018
ASSETS		**$'000**	**$'000**
Non-current Assets			
Property, plant and equipment	11	42,380	53,599
Right-of-Use ("ROU") assets	12	1,402	--
Intangible assets	13	26,255	25,757
Abandonment fund	14	3,378	2,979
Performance bond	15	253	253
Deferred Tax Assets ("DTA")	16	9,362	5,973
		83,030	88,561
Current Assets			
Inventories	17	5,143	3,738
Trade and other receivables	18	9,337	13,343
Derivative financial instruments		85	--
Cash and Cash equivalents	19	13,810	10,201
		28,375	27,282
Total Assets		**111,405**	**115,843**
EQUITY AND LIABILITIES			
Capital and Reserves Attributable to Equity Holders			
Share capital	20	97,692	97,692
Share premium	20	139,879	139,879
Share based payment reserve	21	14,328	13,290
Merger reserves	22	75,467	75,467
Reverse acquisition reserve	22	(89,268)	(89,268)
Translation reserve		(1,649)	(1,638)
Accumulated losses		(186,024)	(176,473)
Total Equity		**50,425**	**58,949**
Non-current Liabilities			
Lease liability	12	841	--
Deferred Tax Liabilities ("DTL")	16	4,188	5,598
Provision for other liabilities	24	44,330	41,802
		49,359	47,400
Current Liabilities			
Trade and other payables	25	10,386	9,147
Lease liability	12	637	--
Provision for other liabilities	24	518	347
Taxation payable	27	80	--
		11,621	9,494
Total Liabilities		**60,980**	**56,894**
Total Equity and Liabilities		**111,405**	**115,843**

Company Statement of Financial Position
at 31 December 2019
(Expressed in United States Dollars)

	Note	2019 $'000	2018 $'000
ASSETS			
Non-current Assets			
Investment in subsidiaries	10	59,306	58,489
Current Assets			
Trade and other receivables	18	218	84
Intercompany	18	3,631	6,539
Derivative financial instruments		85	--
Cash and Cash equivalents.	19	5,286	4,056
		9,220	10,679
Total Assets		**68,526**	**69,168**
EQUITY AND LIABILITIES			
Capital and Reserves Attributable to Equity Holders			
Share capital	20	97,692	97,692
Share premium	20	139,879	139,879
Share based payment reserve		3,628	2,590
Merger reserves		56,652	56,652
Accumulated losses		(229,833)	(228,126)
Total Equity		**68,018**	**68,687**
Current Liabilities			
Trade and other payables	25	508	481
		508	481
Total Liabilities		**508**	**481**
Total Equity and Liabilities		**68,526**	**69,168**

Consolidated Statement of Changes in Equity
for the year ended 31 December 2019
(Expressed in United States Dollars)

	Share Capital	Share Premium	Other Equity	Share Based Payment Reserve	Reverse Acquisition Reserve	Merger Reserves	Translation Reserve	Accumulated Losses	Total Equity
Year ended 31 December 2018	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**
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[1] - discount	--	(3,265)	--	--	--	--	--	--	(3,265)
CLN – conversion	--	--	(590)	--	--	--	--	--	(590)
Share based payment expense (Note 21)	--	--	--	737	--	--	--	--	737
Loss for the year	--	--	--	--	--	--	--	(5,361)	(5,361)
Translation difference	--	--	--	--	--	--	40	--	40
Total comprehensive income 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**
Year ended 31 December 2019									
At 1 January 2019	97,692	139,879	--	13,290	(89,268)	75,467	(1,638)	(176,473)	58,949
Share based payment expense (Note 21)	--	--	--	1,038	--	--	--	--	1,038
Loss for the year	--	--	--	--	--	--	--	(9,647)	(9,647)
Translation difference	--	--	--	--	--	--	(11)	96	85
Total comprehensive loss for the year	--	--	--	--	--	--	(11)	(9,551)	(9,562)
At 31 December 2019	**97,692**	**139,879**	**--**	**14,328**	**(89,268)**	**75,467**	**(1,649)**	**(186,024)**	**50,425**

[1] *On 11 January 2017 the Company issued at a 50% discount 6.6 million USD 1.00 dollar, unsecured CLNs.*

Company Statement of Changes in Equity
for the year 31 December 2019
(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 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 charge	--	--	--	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**
Year ended 31 December 2019							
At 1 January 2019	97,692	139,879	--	2,590	56,652	(228,126)	68,687
Issue of ordinary shares	--	--	--	--	--	--	--
Share based payment charge (Note 21)	--	--	--	1,038	--	--	1,038
Total comprehensive expense for the year	--	--	--	--	--	(1,707)	(1,707)
At 31 December 2019	**97,692**	**139,879**	**--**	**3,628**	**56,652**	**(229,833)**	**68,018**

Consolidated Statement of Cash Flows
for the year ended 31 December 2019
(Expressed in United States Dollars)

	Note	2019 $'000	2018 $'000
Operating Activities			
Loss before taxation		(14,055)	(4,091)
Adjustments for:			
Translation difference		(63)	330
Finance cost – loans and interest	7	174	592
Finance income		(138)	(93)
Finance cost – decommissioning provision	24	1,198	1,557
Share based payment charge	21	1,038	737
DD&A	11-13	9,772	10,694
Loss on disposal of assets	11	--	(6)
Impairment of property, plant and equipment	11	15,187	2,561
Unsecured creditors' claims		--	(192)
		13,113	12,089
Changes In Working Capital			
Inventories	17	(1,454)	28
Trade and other receivables	18	3,638	(9,513)
Trade and other payables	25	1,797	2,731
		17,094	5,335
Income taxation paid		(316)	(128)
Net Cash Inflow From Operating Activities		16,778	5,207
Restructuring related payments			
T&T[1] State creditors (MEEI[2] & BIR[3])		--	(5,835)
		--	(5,835)
Investing Activities			
Purchase of Exploration and Evaluation ("E&E") assets	13	(476)	(170)
Purchase of computer software	13	(99)	(26)
Purchase of property, plant and equipment	11	(12,156)	(12,264)
Net Cash Outflow From Investing Activities		(12,731)	(12,460)
Financing Activities			
Issue of shares (net of costs)	20	--	12,361
Repayment of Convertible Loan Note ("CLN")		--	(770)
Finance income		138	--
Finance cost		--	(94)
Cash payment on leases		(576)	--
Net Cash (Outflow)/Inflow From Financing Activities		(438)	11,497
Increase/(Decrease) in Cash and Cash Equivalents		3,609	(1,591)
Cash and Cash Equivalents			
At beginning of year		10,201	11,792
Increase/(Decrease) in Cash and Cash equivalents		3,609	(1,591)
At end of year	19	13,810	10,201

[1] *Trinidad & Tobago ("T&T")*
[2] *Ministry of Energy and Energy Industries of Trinidad & Tobago ("MEEI")*
[3] *Board of Inland Revenue of Trinidad & Tobago ("BIR")*

Company Statement of Cash Flows
for the year ended 31 December 2019
(Expressed in United States Dollars)

	Note	2019 $'000	2018 $'000
Operating Activities			
Loss before taxation		(1,707)	(2,667)
Adjustments for:			
Translation differences		1	10
Finance income		(233)	(215)
Finance cost		--	418
Share based payment charge		221	123
		(1,718)	(2,331)
Changes In Working Capital			
Trade and other receivables		(4,015)	(4,088)
Trade and other payables		6,730	(802)
		2,715	(4,890)
Taxation Paid		--	--
Net Cash Inflow/(Outflow) from Operating Activities		997	(7,221)
Financing Activities			
Finance income		233	215
Finance cost		--	(94)
Capital contributed to subsidiary	10	--	(6,459)
Issue of shares (net of costs)	20	--	12,361
Repayment of CLN		--	(770)
Net Cash Inflow from Financing Activities		233	5,253
Increase/(Decrease) In Cash and Cash Equivalents		1,230	(1,968)
Cash and Cash Equivalents			
At beginning of year		4,056	6,024
Increase/(Decrease) in Cash and Cash equivalents		1,230	(1,968)
At End of Year	19	5,286	4,056

Notes to the Consolidated Financial Statements
31 December 2019
(Expressed in United States Dollars)

1 **Background and Summary of significant 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. The financial statements are for the Group of Trinity Exploration & Production plc and its subsidiaries.

Background

Trinity Exploration & Production plc ("Trinity" or "the Company" or "Parent") is an independent energy company limited by shares and listed on the Alternative Investment Market ("AIM") of the London Stock Exchange ("LSE"). The Company is incorporated and domiciled in England and the address of the registered office is C/o Pinsent Masons LLP 1 Park Row, Leeds LS1 5AB, United Kingdom ("UK"). Trinity and its subsidiaries (together "the Group") are involved in the exploration, development and production of oil reserves in 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, except certain financial assets and liabilities (including derivative financial instruments) and certain classes of property, plant and equipment – which are measured at fair value through the Consolidated Statement of Comprehensive Income. Accounting policies have been applied consistently, other than where a new accounting policy has been adopted.

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 $1.7 million (2018: $2.7 million loss).

Going Concern

The Directors have adopted the going concern basis in preparing the Financial Statements.

In making their going concern assessment, the Board of Directors ("Board") have considered the Group's, and therefore the Company's, current financial position, budget and various cash flow forecast scenarios. The Directors have attempted to consider the potential impact of the COVID-19 pandemic on the Group's operational capabilities, liquidity and financial position over the next twelve month period and beyond. This going concern assessment has taken into account the current measures being put in place by the Group to preserve cash and reduce discretionary expenditure during a period when the Group is having to rapidly adapt to a significantly lower oil price environment.

The Group started 2020 with a strong operating and financial position, a 2019 average production rate of 3,007 bopd (Q1 2020 3,291), cash in hand and at bank of $13.8 million (Q1 2020 $14.2 million (unaudited)), no outstanding debt, crude oil hedges in place and undrawn credit facilities of $2.7 million, repayable on demand, which are available for general working capital purposes).

In making their going concern assessment, the Directors have considered what they consider to be a wide range of plausible scenarios for future oil prices, production volumes and discretionary expenditure reductions which could be implemented in response to differing oil price and production scenarios.

In making their going concern assessment the Board has looked at a number of forecast scenarios, the principal two of which are summarised below:

1. Base Case

The Base Case forecast assumes:

- Future oil prices are in line with the forward curve prevailing as at the end of April 2020, with an average realised oil price of $26.8/bbl in the period to May 2021. The forward price curve applied in the Base Case starts at $15.4/bbl in May 2020, increasing each month up to $31.37/bbl in May 2021;
- Average 2020 forecast production of 3,271 bopd and average 2021 forecast to May production of 3,123 bopd, with production being maintained by RCPs, WOs and swabbing activities but no new drilling (Q1 2020 actual average production rate of 3,291 bopd);
- The benefit of cost reduction measures across Opex, G&A and Capex which have already been implemented by the Group;
- The Group receives the benefit of the crude oil price hedges currently in place; and
- The Group repays the CIBC FirstCaribbean International Bank (Trinidad & Tobago) Limited ("CIBC") $2.7 million bank facility in October 2020 and does not receive any cash in relation to the $2.7 million VAT Bonds for which the Group has applied to the BIR.

The Base Case forecast showed that the Group will remain in a relatively strong financial position for the next twelve months, being able to pay its debts as they fall due, with available cash in May 2021 of approximately $16.0 million. Management considers this is a reasonable scenario that reflects its best estimate of the future oil price, production profile and cost savings which have already been implemented.

2. Risked Case

The Risked Case forecast is essentially a stress test which assumes:

- A flat oil price of $10.0/bbl over the period May 2020 to May 2021. This assumption represents a 63% decline on the forward curve assumed in the Base Case;
- Average 2020 forecast production of 2,829 bopd and average 2021 forecast production to May of 2,566 bopd, with production stressed to reflect the potential impact of reduced operational capability due to COVID-19. These represents a 15% decline in the production assumptions used in the Base Case in the period from January 2020 to May 2021, equivalent to a loss of an average 475 bopd over that period;
- Additional cost reductions of $2.8 million can be implemented across Opex and G&A, reflecting the reduced activity associated with the lower forecast production profile, and other cost saving measures which Management are confident can be implemented; and
- All other assumptions remain the same as the Base Case above.

The Board considers that these assumptions represent a relatively severe scenario but, given the difficulty of predicting the impact of the COVID-19 pandemic, they are not entirely implausible. The Risked Case forecast showed that, whilst the Group would still be able to pay its debts as they fall due over the next twelve months, the Group's financial position would deteriorate significantly with ending cash in May 2021 of approximately $4.0 million. This scenario relies on the ability of Management to implement the planned cost reduction measures, and it is also important to note that the Group's financial position would deteriorate further were these severe conditions to continue beyond the twelve month going concern forecast period. Should such a severe scenario arise and persist during the next twelve months, the Board will consider various means by which to adapt the business model in order to create additional financial headroom.

Based on these scenarios, when combined with mitigating actions that are within the Group's control, and having considered the potential impact of a period of operational disruption from the COVID-19 pandemic, the Directors currently believe the Group can maintain sufficient liquidity and a positive cash balance, and remain in operational existence, for at least the next twelve months.

The Board has carried out a robust assessment of the principal risks facing the Group as a result of the COVID-19 pandemic and reduced oil price, including those that would threaten its crude oil production and disposal, future performance, solvency or liquidity. The Board has also considered its ability to mitigate the principal risks facing the Group. Whilst the Board is confident of its ability to mitigate the principal risks facing the Group in most circumstances, the occurrence of certain risk events, when combined with the Risked Scenario assumptions set out above, give rise to a material uncertainty regarding the Group's ability to continue as a going concern.

As a result, at the date of approval of the financial statements, there are material uncertainties over the potential impact of COVID-19 on the Group's operational activities, as a result of its potential impact on the oil price, and should Management be unable to implement mitigating plans including cost reduction measures. These material uncertainties may cast significant doubt upon the Group's and Company's ability to continue as a going concern. Notwithstanding these material uncertainties, the Directors have a reasonable expectation that the Group has adequate resources to continue in existence for at least twelve months post approval of these financial statements and is poised for continued growth when market conditions improve. For this reason the Board have concluded it is appropriate to continue to adopt the going concern basis of accounting in the preparation of the financial statements. Accordingly, the financial statements do not include the adjustments that would result if the Group were unable to continue as a going concern.

New and amended standards adopted by the Group:

The Group, and Company has applied the following standards and amendments for the first time for annual reporting period commencing 1 January 2019:

IFRS 16 Leases	IFRS 16, is a new accounting standard which resulted in certain leases being recognised on the balance sheet or Consolidated Statement of Financial Position, as the distinction between operating and finance leases was removed. Under the new standard, an asset (the right to use the leased item) and a financial liability to pay rentals are recognised. The impact of adoption is discussed under Changes in accounting policies (Adoption of IFRS 16 Leases ("IFRS 16").	Periods beginning on / after 1 January 2019
IFRS 9 Financial Instruments - Amendment	The standard IFRS 9 has been effective from January 2018, but after its first year, there is an amendment, *Prepayment Features with Negative Compensation*. This amendment relates to the classification of certain financial assets, namely those with specific prepayment options. The amendment had no impact to the Financial statements as Trinity does not have prepayments with specific payment options.	Periods beginning on / after 1 January 2019
IFRIC 23 – Uncertainty over Income Tax Treatments	It may be unclear how tax law applies to a particular transaction or circumstance, or whether the BIR will accept Trinity's tax treatment. International Accounting Standards ("IAS") 12 *Income Taxes* specifies how to account for current and deferred tax, but not how to reflect the effects of uncertainty. IFRIC 23 provides requirements that add to the requirements in IAS 12 by specifying how to reflect the effects of uncertainty in accounting for income taxes. This new standard has no impact on Trinity's Income taxes.	Periods beginning on / after 1 January 2019

The Group also elected to adopt the following amendments early:

Amendments to IAS 1 and IAS 8	The amendment relates to the definition of material information. According to the new definition, information is material if omitting, misstating or obscuring it could reasonably be expected to influence decisions that the primary users of general purpose financial statements make on the basis of those financial statements, which provide financial information about a specific reporting entity.	Periods beginning on / after 1 January 2020

The Group had to change its accounting policies as a result of adopting IFRS 16. The Group elected to adopt the new rules retrospectively but recognised the cumulative effect of initially applying the new standard on 1 January 2019.

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 2019 reporting periods and have not been early adopted by the Group. These standards are not expected to have a material impact on the entity in the current or future reporting periods or on foreseeable future transactions.

IFRS 3 Business Combinations - Amendments	The newest amendment introduces a new definition of business combination. It is very important to distinguish between the situations when the investor acquires a business or when the investor acquires just a group of assets. To identify whether an acquired set of activities or assets is not a business, there is an optional fair value concentration test. The concentration test is met if substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets. The test is based on gross assets, not net assets. Under IFRS 3 the reason for the distinction is that the accounting method for the new acquisition depends on what it is: - If you acquire a business, then you apply full consolidation method under IFRS 3, - If you acquire a group of assets, then you apply different accounting method, e.g. under IAS 16 Property, plant and equipment or under IFRS 11 Joint Operations, or other.	Periods beginning on / after 1 January 2020

Changes in accounting policies

- **Adoption of IFRS 16 Leases ("IFRS 16")**

The Group adopted IFRS 16, effective 1 January 2019 but has not restated comparatives for the 2018 reporting period, as permitted under the simplified transitional approach. This is a new accounting standard resulting in almost all leases being recognised on the Consolidated Statement of Financial Position, 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 (less than twelve months) and low-value leases (less than $5,000).

On adoption of IFRS 16, the Group has recognised ROU assets and lease liabilities, but under the practical expedient permitted by the standard, elected not to reassess whether a contract is, or contains a lease at the date of initial application. Instead, for contracts entered into before the transition date the Group relied on its assessment made applying IAS 17 and IFRIC 4 determining whether an arrangement contains a Lease.

a) Adjustments recognised on adoption of IFRS 16

ROU assets and Lease Liabilities recognised in the Consolidated Statement of Financial Position.

	31 December 2019	01 January 2019
ROU recognised	$'000	$'000
Non- current assets:		
Copiers	8	21
Vehicles	1,040	--
Rental house	59	79
Office Building	295	393
	1,402	**493**
Lease Liabilities recognised		
Current lease liabilities	637	151
Non-current lease liabilities	841	342
	1,478	**493**

The ROU assets relate to motor vehicles, office building, staff house and office equipment leases that met the recognition criteria of a Lease under IFRS 16.

i. Impact on Earnings per share

	IAS 17	IFRS 16	Difference
	$'000	$'000	$'000
Expenses			
Production costs	16,857	16,426	431
G&A expenses	5,732	5,589	143
DD&A	9,295	9,772	(477)
Net Finance cost	1,061	1,234	(173)
	32,945	33,021	(76)
Total Comprehensive loss for the period	**(9,486)**	**(9,562)**	**(76)**
Earnings per Share	(0.02)	(0.02)	

ii. Measurement of lease liabilities

	2019
	$'000
Operating lease commitments disclosed as at 31 December 2018	588
Discounted using the lessee's incremental borrowing rate as at the date of initial application	493
Lease liability recognised as at 1 January 2019	**493**
Of which are:	
Current lease liabilities	151
Non-current lease liabilities	342
	493

iii. Practical expedients applied

In applying IFRS 16 for the first time, the Group has used the following practical expedients permitted by the standard:

- the use of a single discount rate to a portfolio of leases with reasonably similar characteristics
- the accounting for operating leases with a remaining lease term of less than twelve months as at January 2019 as short-term leases
- the exclusion of initial direct costs for the measurement of the ROU asset at the date of initial application,
- and the use of hindsight in determining the lease term where the contract contains options to extend or terminate the lease.

The Group has chosen to measure the ROU assets recognised at the amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments, immediately before the date of adoption for all ROU assets recognised. There is therefore no adjustment to opening retained earnings.

The Group has also elected not to reassess whether a contract is, or contains a lease at the date of initial application. Instead, for contracts entered into before the transition date the Group relied on its assessment made applying IAS 17 and IFRIC 4 determining whether an arrangement contains a Lease.

b) The Group's leasing activities and how these are accounted for:

The Group has lease agreements for various types of assets; motor vehicles, office buildings, staff house and office equipment leases are typically made for fixed terms ranging between 1-3 years but may have extension options.

Lease terms are negotiated on an individual basis and contain a range of different terms and conditions.
Until the 2018 financial year, leases of property, plant and equipment were classified as operating leases or finance leases, and the Group had no finance leases. Payments made under operating leases (net of any incentives received from the lessor) were charged to the Consolidated Statement of Comprehensive Income on a straight-line basis over the period of the lease.

From 1 January 2019, leases are recognised as a ROU asset and a corresponding liability at the date at which the leased asset is available for use by the Group. Each lease payment is allocated between the liability and finance cost. The finance cost is charged to profit or loss over the lease period so as to produce a constant periodic rate of interest on the remaining balance of the liability for each period. The ROU asset is depreciated over the shorter of the asset's useful life and the lease term on a straight-line basis. Assets and liabilities arising from a lease are initially measured on a present value basis. Lease liabilities include the net present value of fixed payments (including in-substance fixed payments), less any lease incentives receivable.

The lease payments are discounted using a 9.25% incremental borrowing rate, being the rate that the Group believes it would have to pay to borrow the funds necessary to obtain an asset of similar value in a similar economic environment with similar terms and conditions.

ROU assets are measured at cost comprising the following:

- the amount of the initial measurement of lease liability;
- any lease payments made at or before the commencement date less any lease incentives received;
- any initial direct costs; and
- restoration costs.

Payments associated with short-term leases and leases of low-value assets are recognised on a straight-line basis as an expense in profit or loss. Short-term leases are leases with a lease term of twelve months or less. Low-value assets comprise of assets valued less than $5,000.

Basis of consolidation

The consolidated financial information incorporates the financial information of the Group 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 Consolidated 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:

	2019		2018	
	$	£	$	£
Average rate TTD= $/£	6.759	8.617	6.762	9.107
Closing rate TTD= $/£	6.762	8.965	6.781	8.644

(b) Transactions and balances

Foreign currency transactions are translated into the functional currency using the exchange rates at the dates of the transactions. FX gains/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.

FX gains/losses that relate to borrowings are presented in the statement of profit or loss, within finance costs. All other FX gains/losses are presented in the statement of profit or loss on a net basis within administrative 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 Statement of Financial Position presented are translated at the closing rate at the date of that Consolidated Statement of Financial Position
- 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 ("E&E") assets

i) Capitalisation

E&E 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 E&E 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 E&E of assets includes*:*

− *Licence and property acquisition costs*

Exploration and property leasehold acquisition costs are capitalised within E&E assets.

− *E&E 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, E&E expenditures are written off as a dry hole when that determination is made.

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

ii) Impairment

E&E 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 E&E assets' carrying amount exceed their recoverable amount. The recoverable amount is the higher of the E&Es assets' fair value less costs of disposal and their Value In Use ("VIU"). For the purposes of assessing impairment, the E&E 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 E&E in the specific area is budgeted or planned.
- Whether E&E 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; and/or
- Whether sufficient data exists to indicate that, although a development in the specific area is likely to proceed, the carrying amount of the E&E asset is unlikely to be recovered in full from successful development or by sale.

(b) 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 four year useful life, based on pattern of benefits (straight-line is the default) and charge recognised under DD&A.

Property, plant and equipment

(a) Oil & 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 E&Es 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 Consolidated Statement of Comprehensive Income and any shortfall between the proceeds and the carrying amount is recorded as a loss on disposal in the Consolidated 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, market capital below net assets, 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 CGU) for which there are separately identifiable cash flows. The CGU applied for impairment test purposes is generally the field. These fields are the same as that used for reserves reporting purposes.

iii) Producing Assets – DD&A

The provision for DD&A of developed and producing Oil & Gas Assets are calculated using the unit-of-production method. Oil & 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 Consolidated 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 & 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 Consolidated Statement of Comprehensive Income.

Repairs and maintenance are charged to the Consolidated 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 ("FVLCD") and VIU. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows (CGUs). 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, RCPs and WOs 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 Consolidated 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 Consolidated Statement of Financial Position.

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 thirty 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 the expected loss rates using a provision matrix that is based on the 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 lost 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

There are 4 types of financial assets that are subject to the Expected Credit Losses ("ECL") model. However, the Group applies the ECL model to trade receivables for sales of inventory and from the provision of consulting services as well as Intercompany receivables. While Cash and Cash equivalents are also subject to the impairment requirements of IFRS 9, the identified impairment loss was immaterial.

(i) Trade receivables

The Group applies the IFRS 9 simplified approach to measuring ECL which uses a lifetime expected loss allowance for all trade receivables.

Financial assets recognition of impairment provisions under IFRS 9 is based on the ECL model. The ECL model is applicable to financial assets classified at amortised costs 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 forward looking estimates. This is then applied to the gross carrying amount of the receivables to arrive at the loss allowance for the period.

(ii) Intercompany receivables

The Company applies IFRS 9 through the recognition of ECL for intercompany. Intercompany positions eliminate in the consolidated financial statements. In measurement of the ECL, IFRS 9 notes that the maximum period over which expected impairment losses is measured is the longest contractual period where the Company is exposed to credit risk. The 3-stage general impairment model was used, Probability of Default ("PD") x Loss Given Default ("LGD") x Exposure at Default ("EAD"). Measurement of the ECL at a probability-weighted amount that reflects the possibility of a credit loss occurs, and the possibility that no credit loss occurs and even if the possibility of a credit loss occurring is low.

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 DTA 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, DTL 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.

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

DTL 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.

DTA 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 Tax

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 requires that revenue is recognised by performance obligation, as or when each performance obligation is satisfied, and that variable elements of pricing are recognised and to the extent that it is not highly probable they will be reversed.

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

Crude 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 based on prices determined by Heritage/Petrotrin, with agreed contractual adjustments for 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 Consolidated 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 twelve months after the Consolidated 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.

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

The Group has changed its accounting policy for leases where the Group is the lessee. The new policy is described in Note 12 and the impact of the change seen in section Changes in accounting policies.
Until 31 December 2018, leases of property, plant and equipment where the Group, as lessee, had substantially all the risks and rewards of ownership were classified as finance leases.

Finance leases were capitalised, at the lease's inception at the fair value of the leased property or, if lower, the present value of the minimum lease payments. The corresponding rental obligations, net of finance charges, were included in other short-term and long-term payables.

Leases in which a significant portion of the risks and rewards of ownership were not transferred to the Group as lessee were classified as operating leases see Note 29. Payments made under operating leases (net of any incentives received from the lessor) were charged to the Income 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.

Derivative financial Instruments 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 oil price derivative financial instruments (categorised as Other Expenses) are measured at fair value through profit and loss.

Financial assets at fair value through profit or loss 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 twelve 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 Statement of Financial Position only when it is extinguished; that is, when the obligation specified in the contract is discharged, cancelled or expired.

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 the Executive Management Team which comprises of; the Executive Chairman, Managing Director, Chief Operations Officer and Chief of Staff & General Counsel, 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 programme 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) FX risk

The Group is exposed to FX risk primarily with respect to the United States dollar. FX 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 2019, 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 $3.0 million (2018: $2.9 million) lower/higher, mainly as a result of FX gain/losses on translation of USD-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 2019, if commodity prices had been 20% higher/lower with all other variables held constant, post-tax profit/(loss) for the year would have been $12.7 million (2018: $12.5 million) lower/higher. The sensitivity doesn't take into consideration the impact of the oil price derivative financial instruments in place.

(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 2019, there were no loan commitments to attract interest rates on foreign currency-denominated borrowings, (2018: 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 until 30 November 2018 and Heritage effective 1 December 2018.

The Group applies an IFRS 9 simplified model for measuring the 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, Management made the decision in keeping with the standard to calculate a provision for long outstanding receivables associated mainly with the Petrotrin outstanding sales receipts. A provision matrix was applied to determine the historical and forward looking loss rates which was used to ultimately calculate an estimated credit loss allowance, which resulted in a provision being made of $0.2 million.

For the Heritage sales, the ECL was nil as all sales payment were made during the stipulated time frame. However, ECL was also calculated on other receivable balances and a provision of $0.4 million was derived.
The Company also assessed impairment through the 3-stage approach to derive at the ECL. Through assessing impairment via this method, a provision amount of $0.1 million was calculated.

(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 $13.8 million (2018: $10.2 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 table below analyses the Group's and Company'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 twelve months equal their carrying balances as the impact of discounting is not significant.

	Less than 1 year	More than 1 year	Total Contractual Cash flows	Carrying amount
At 31 December 2019	$'000	$'000	$'000	$'000
Non-derivatives				
Trade and other payables	10,386	--	10,386	10,386
Decommissioning	--	44,330	44,330	44,330
Total Non-derivatives	**10,386**	**44,330**	**54,716**	**54,716**
At 31 December 2018	$'000	$'000	$'000	$'000
Non-derivatives				
Trade and other payables	9,147	--	9,147	9,147
Decommissioning	--	41,803	41,803	41,803
Total Non-derivatives	**9,147**	**41,803**	**50,950**	**50,950**

(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)

	2019 **$'000**	**2018** **$'000**
Net cash	(13,810)	(10,201)
Total equity	50,425	58,949
Total capital	36,615	48,748
Gearing ratio	(37.7)%	(20.9%)

(e) **Fair value estimation**

The Group and Company have classified its financial instruments into the three levels prescribed under the accounting standards.

Level 1: The fair value of financial instruments traded in active markets (such as publicly traded derivatives, and equity securities) is based on quoted market prices at the end of the reporting period. The quoted market price used for financial assets held by the Group is the current bid price. These instruments are included in level 1.

Level 2: The fair value of financial instruments that are not traded in an active market (for example, over-the-counter derivatives) is determined using valuation techniques which maximise the use of observable market data and rely as little as possible on entity-specific estimates. If all significant inputs required to fair value an instrument are observable, the instrument is included in level 2.

Level 3: If one or more of the significant inputs is not based on observable market data, the instrument is included in level 3. This is the case for unlisted equity securities.

Fair value measurements using significant unobservable inputs (Level 3)

	$'000
1 January 2019	--
Gains recognised	7
Expense	78
31 December 2019	**85**

3. Critical Accounting Estimates and Judgements

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 and the Company'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) **Recoverability of DTA**

DTA 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 DTA 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 DTA recognised which can result in a charge or credit in which the change occurs. The Group has concluded that the DTA recognised will be recoverable using approved business plans and budgets for the specific subsidiaries in which the DTA arose.

(b) **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 a rate based on maturity ranging between 2.13%-3.07% (2018: 2.69%-2.90%) and a core inflation rate at 2% (2018: 2%), See Note 24: Provision for other liabilities. The impact in 2019 of a 1% change in these variables is as follows:

	Consolidated Statement of Financial Position: Obligation	**Consolidated Statement of Comprehensive: Income/Expense**
	2019	**2019**
	$'000	**$'000**
<u>Discount rate</u>		
1% increase in assumed rate	(6,794)	167
1% decrease in assumed rate	8,212	(273)
<u>Inflation rate</u>		
1% increase in assumed rate	8,199	231
1% decrease in assumed rate	(6,907)	(193)

(c) **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 2019 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 E&E 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 DTA 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 2019 all subsidiaries onshore and offshore proved and probable ("2P") reserve estimates were re-evaluated by Management and approved by the Board.

(d) **Impairment of Property, Plant And Equipment**

Management performs impairment assessments on the Group's property, plant and equipment once there are indicators of impairment. Triggers for impairment relates to changes in the key factors that impact on impairment which are production, oil price, capital expenditures and operating expenditures. In order to test for impairment, the higher of fair value less costs of disposal and values in use calculations are prepared 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 2019 an impairment charge of $15.2 million was recognised on the Group's property, plant and equipment (2018: $2.6 million) see Note 11. The impairment charge resulted in the carrying amount of the respective CGUs being written down to their recoverable amount.

Oil & Gas Assets $15.2 million (2018: $2.6 million) impairment

As part of this assessment, Management has carried out an impairment test on the Oil & 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 FVLCD and VIU. The FVLCD is the amount that a market participant would pay for the CGU less the cost of disposal. The FVLCD 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 9-23 year economic lives based on the field economic life profile. The field economic life profile was derived by using licence extension data which is permitted in accordance with the Society of Petroleum Engineers ("SPE") reserves reporting guidelines outlined in the 2018 Petroleum Resource Management System ("PRMS"). While there is the risk that licences may not be renewed upon expiry, Management considers this to be very low based on historic precedent. 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 impairment calculation considers the decommissioning asset and liability used to derive the impairment charge.

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 and decommissioning liabilities pertaining to the CGU's; and a discount rate utilised for the purposes of deriving a recoverable value.

	2020	2021	2022	2023	2024	2025
Realised price	58.6	54.1	52.0	51.4	51.5	52.1

If the price deck used in the impairment calculation had been 10% lower than Management's estimates at 31 December 2019, the Group would have $3.5 million decrease on impairment of Oil & Gas Assets (2018: $3.4 million increase), resulting from the impact of SPT being incurred in the base case, with a long-term realised price of $52.8/bbl, but not in the 10% sensitivity. A lower realised price, below the SPT threshold price, will increase the FVLCD, and decrease the impairment charge. If the price deck used in the impairment calculation had been 10% higher than Management's estimates at 31 December 2019, the Group would have $6.0 million decrease on impairment of the Oil & Gas Assets (2018: $0.2 million decrease). Oil price forecasts at end of March 2020 indicate a long-term price of $42.8/bbl, which would have resulted in an additional $4.1 million increase in the impairment charge. The valuation is considered to be a level 3 in the fair value hierarchy due to unobservable inputs used in the valuation.

For the year ended 31 December 2019, Management's estimate of the Group's cost of capital was 13% (2018:13%). If the estimated cost of capital of 13% (2018: 13%) used in determining the post-tax discount rate for the CGU's had been 1% lower than Management's estimates the Group would have $0.7 million decrease on impairment position for 2019 (2018: $0.6 million decrease) against Oil & 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 $0.7 million increase on impairment for 2019 (2018: $0.6 million).

(e) **Impairment of intangible E&E assets**

At the end of a review for impairment triggers was carried out and there were no further impairment losses realised against the carrying values of the Group's E&E assets.

The Group reviews the carrying values of intangible E&E assets when there are impairment indicators which would tell whether an E&E asset has suffered any impairment. The amounts of intangible E&E 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 Operating Segments, in regard to the determination of operating segments, and concluded that the Group has only one significant operating segment being the exploration and development, production and extraction of hydrocarbons.

All revenue is generated from crude oil sales in T&T to one customer, Heritage (previously Petrotrin until 30 November 2018). All non-current assets of the Group are located in T&T.

5 Operating Profit Before Exceptional Items

	2019 $'000	**2018 $'000**
Operating profit before exceptional items is stated after taking the following items into account:		
DD&A (Note 11)	9,218	10,664
Depreciation on ROU (Note 12)	477	--
Amortisation of computer software (Note 13)	77	30
Employee costs (Note 30)	7,773	7,972
Operating lease rentals	--	568
Inventory recognised as expense, charged to operating expenses	104	175

Auditors' remuneration

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

	2019 $'000	2018 $'000
- Fees payable to the Company's auditors' and their affiliated firms for the audit of the parent Company and consolidated financial statements:		
PricewaterhouseCoopers LLP (UK based)	153	153
PricewaterhouseCoopers Limited (T&T based)	124	95
- Fees payable to the Company's auditors' for other services:		
The audit of Company's subsidiaries	20	18
Audit related assurance services – interim review	38	35
Total assurance	**335**	**301**
Tax advisory	--	3
Other advisory	--	12
Total auditors' remuneration	**335**	**316**

All fees are in respect of services provided by PricewaterhouseCoopers LLP and their affiliated firms. 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, and 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 Consolidated Statement of Comprehensive Income. An analysis of the amounts presented as exceptional items in these financial statements are highlighted below.

	2019	2018
Exceptional items:	**$'000**	**$'000**
Reversal of bad debt written off	--	(205)
Unsecured creditor compromise	--	(70)
Impairment of property, plant and equipment (Note 11)	15,187	2,561
Fees relating to corporate restructuring	--	26
Exceptional charge/(credit)	**15,187**	**2,312**

Exceptional items 2019:

<u>Impairment on Property, Plant and Equipment</u>
$15.2 million charge resulting from impairment losses in Onshore and West Coast assets

Exceptional items 2018:

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

<u>Unsecured creditor compromise</u>
$0.1 million gain under the creditor settlements arising from compromised balances with suppliers

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

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

7 Finance income

	2019 $'000	2018 $'000
Interest Income	138	93

Finance costs

	2019 $'000	2018 $'000
Decommissioning – Unwinding of discount (Note 24)	(1,198)	(1,557)
Interest on Leases	(174)	--
Interest on loans	--	(592)
	(1,372)	**(2,149)**

8 Income Taxation

	2019 $'000	2018 $'000
Current tax		
Petroleum profits tax	--	5
Unemployment levy	390	--
Deferred Tax		
- Current year		
Movement in asset due to tax losses recognised (Note 16)	(3,389)	(1,794)
Movement in liability due to accelerated tax depreciation (Note 16)	(1,409)	3,059
Income tax (credit) /expense	**(4,408)**	**1,270**

The Group's effective tax rate varies from the statutory rate for UK companies of 19% (2018:19%) as a result of the differences shown below:

	2019 $'000	2018 $'000
Loss before taxation	**(14,055)**	**(4,091)**
Tax (credit)/charge at expected rate of 19% (2018: 19%)	(2,670)	(777)
Effects of:		
Higher overseas tax rate	1,525	28
Disallowable expenses	5,516	1,917
Allowable expenses	(635)	(9,549)
Tax losses recognised for DTA	8,366	3,363
Tax losses utilised to recognise DTA	(7,905)	10,860
Movement in losses recognised	(3,389)	--
DTA previously recognised	(5,973)	(4,197)
Green Fund and Business Levy	446	230
Other differences	311	(605)
Income Tax (credit)/expenses	**(4,408)**	**1,270**

Taxation losses at 31 December 2019 available for set off against future taxable profits amounts to approximately $240.2 million (2018: $244.1 million). Tax losses of $17.0 million were recognised as DTA in 2019 (2018:$10.9 million). These losses do not have an expiry date and have not yet been confirmed by the BIR and Her Majesty Revenue and Customs of the United Kingdom ("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 $'000	Weighted Average Number Of Shares '000'	Earnings Per Share $
Year ended 31 December 2019			
Basic	(9,562)	384,049	(0.02)
Diluted	(9,562)	384,049	(0.02)
Year ended 31 December 2018			
Basic	(5,321)	330,579	(0.02)
Diluted	(5,321)	330,579	(0.02)

Impact of dilutive ordinary shares:

Diluted earnings per share is calculated by adjusting the weighted average number of ordinary shares outstanding to assume conversion of all dilutive potential ordinary shares. The awards issued under the Company's LTIP comprising 32,073,822 less forfeited 283,004 are considered potential ordinary shares. Share Options of 1,975,084 are considered potential ordinary shares and have not been included as the exercise hurdle would not have been met.

There was no impact on the weighted average number of shares outstanding during 2019 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 2019.

10 Investment In Subsidiaries

	Company	
	2019 $'000	**2018 $'000**
Opening balance	58,489	51,416
Capital contributed to subsidiary	--	6,459
Share based payment	817	614
Closing balance	**59,306**	**58,489**

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 subsidiaries at 31 December 2019 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, LS1 5AB, UK	Holding Company	99.99998 %
Trinity Exploration & Production (UK) Limited	13 Queen's Road, Aberdeen, AB15 4YL, UK	Holding Company	100 %
Trinity Exploration and Production Services (UK) Limited	c/o Pinsent Masons LLP, 1 Park Row, Leeds, LS1 5AB, UK	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 2019	Plant & Equipment $'000	Leasehold & Buildings $'000	Oil & Gas Assets $'000	Other $'000	Total $'000
Opening net book amount at 1 January 2019	962	1,705	50,932	--	53,599
Additions	369	111	11,676	--	12,156
Adjustment to decommissioning estimate (Note 24)	--	--	1,031	--	1,031
Impairment[1]	--	--	(15,187)	--	(15,187)
DD&A charge for year	(190)	(164)	(8,864)	--	(9,218)
Translation difference	--	--	(1)	--	(1)
Closing net book amount at 31 December 2019	**1,141**	**1,652**	**39,587**	**--**	**42,380**
At 31 December 2019					
Cost	13,760	3,356	298,879	336	316,331
Accumulated DD&A and impairment	(12,619)	(1,704)	(259,291)	(336)	(273,950)
Translation difference	--	--	(1)	--	(1)
Closing net book amount	**1,141**	**1,652**	**39,587**	**--**	**42,380**

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**

1 *An impairment loss of $15.2 million (2018: $2.6 million) was recognised on Oil & Gas Assets (see Note 3 (e)) 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 Leases

On adoption of IFRS 16, the Group has recognised ROU assets and lease liabilities

(iii) Amounts recognised in the Consolidated Statement of Financial Position

The Consolidated Statement of Financial Position shows the following amounts relating to leases:

	31 December 2019	01 January 2019
	$'000	$'000
Right-of-use assets		
Non-current assets	1,402	493
Lease Liabilities		
Current	637	151
Non-current	841	342
	1,478	**493**

The ROU assets relate to Motor vehicles, Office building, Staff house and Office equipment leases that met the recognition criteria of a Lease under IFRS 16.

On 1 January 2019, the Group adopted IFRS 16 and recognised lease assets and lease liabilities in relation to leases agreements that were previously classified as 'operating leases' under IAS 17, 'Leases'. Costs associated with operating leases were previously presented in Operating Expenses. For adjustments recognised on adoption of IFRS, please refer to Note 1.

Additions to the ROU assets during the 2019 financial year were $0.1 million

(iv) Amounts recognised in the Consolidated Statement of Comprehensive Income

The Consolidated Statement of Comprehensive Income shows the following amounts relating to leases:

	2019	2018
	$'000	$'000
Depreciation charge of ROU assets		
Depreciation	(477)	--
Interest expense (including finance cost)	(173)	--

The total cash outflow for leases in 2019 was $0.6 million

(iii) The Group's leasing activities and how these are accounted for

The Group leases various offices, equipment, staff house and vehicles. Rental contracts are typically made for fixed periods of 6 months to 4 years but may have extension options as described in (iv) below.

Contracts may contain both lease and non-lease components. There were no non-lease components identified and as such the Group allocates the consideration in the contract to a single lease component based on their relative stand-alone prices.

Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions. The lease agreements do not impose any covenants other than the security interests in the leased assets that are held by the lessor. Leased assets may not be used as security for borrowing purposes.

Until the 2018 financial year, leases of property, plant and equipment were classified as operating leases, see Note 1 for details. From 1 January 2019, leases are recognised as a ROU asset and a corresponding liability at the date at which the leased asset is available for use by the Group.
Assets and liabilities arising from a lease are initially measured on a present value basis. Lease liabilities include the net present value of the following lease payments:

- fixed payments (including in-substance fixed payments), less any lease incentives receivable;
- variable lease payment that are based on an index or a rate, initially measured using the index or rate as at the

commencement date;

- amounts expected to be payable by the Group under residual value guarantees;
- the exercise price of a purchase option if the Group is reasonably certain to exercise that option; and
- payments of penalties for terminating the lease, if the lease term reflects the Group exercising that option.

Lease payments to be made under reasonably certain extension options are also included in the measurement of the liability.

The lease payments are discounted using the Group's incremental borrowing rate, being the rate that the Group would have to pay to borrow the funds necessary to obtain an asset of similar value to the ROU asset in a similar economic environment with similar terms, security and conditions. To determine the incremental borrowing rate, Trinity received an indicative third party lending rate from First Citizens Bank Limited (T&T based bank).

The Group is exposed to potential future increases in variable lease payments based on an index or rate, which are not included in the lease liability until they take effect. When adjustments to lease payments based on an index or rate take effect, the lease liability is reassessed and adjusted against the ROU asset.

Lease payments are allocated between principal and finance cost. The finance cost is charged to profit or loss over the lease period so as to produce a constant periodic rate of interest on the remaining balance of the liability for each period. ROU assets are measured at cost comprising the following:

- the amount of the initial measurement of lease liability;
- any lease payments made at or before the commencement date less any lease incentives received;
- any initial direct costs; and
- restoration costs.

ROU assets are generally depreciated over the shorter of the asset's useful life and the lease term on a straight-line basis. The Group applies the straight-line method of depreciation, where the ROU asset is depreciated over the lease term.

The Group has chosen to measure the ROU assets recognised at the amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments, immediately before the date of adoption for all ROU assets recognised. There is therefore no adjustment to opening retained earnings.

(iv) Extension and termination options

Extension, and termination options are included in a few leases within the Group. These are used to maximise operational flexibility in terms of managing the assets used in the Group's operations. The majority of extension options held are exercisable only by the Group and not by the respective lessor.

In determining the lease term, Management considers all facts and circumstances that create an economic incentive to exercise an extension option, or not exercise a termination option. Extension options (or periods after termination options) are only included in the lease term if the lease is reasonably certain to be extended (or not terminated).

13 Intangible Assets

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

	Computer Software $'000	E&E assets $'000	Total $'000
At 1 January 2019	246	25,511	25,757
Additions	99	476	575
Amortisation	(77)	--	(77)
At 31 December 2019	**268**	**25,987**	**26,255**
At 1 January 2018	250	25,341	25,591
Additions	26	170	196
Amortisation	(30)	--	(30)
At 31 December 2018	**246**	**25,511**	**25,757**

Computer Software: In 2019, capital cost incurred for software acquisition. The initial capital costs were incurred in 2018 with a cost of $0.3 million, and a total accumulated depreciation to date of $0.1 million

E&E assets: Represents the cost for the TGAL 1 exploration well and further field E&E cost. The Group tests whether E&E assets has suffered any impairment triggers on an annual basis and there were no impairment triggers (2018: nil)

14 Abandonment Fund

	2019 $'000	2018 $'000
At 1 January	2,979	1,650
Additions	399	1,329
At 31 December	**3,378**	**2,979**

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.

15 Performance Bond

	2019 $'000	2018 $'000
At 1 January and 31 December	253	253

A Performance Bond in favour of Heritage/Petrotrin was put in place on 3 July 2017 of $ 0.3 million at 1.75% rate per annum, executed with First Citizens Bank Limited 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.

16 Deferred Income Taxation

Group

The analysis of DTA is as follows:

	2019 $'000	2018 $'000
DTA:		
-DTA to be recovered in more than 12 months	(5,127)	(5,238)
-DTA to be recovered in less than 12 months	(4,235)	(735)
DTL:		
-DTL to be settled in more than 12 months	4,188	5,598
Net DTA	**(5,174)**	**(375)**

The movement on the deferred income tax is as follows:

	2019 $'000	2018 $'000
At beginning of year	(375)	(1,641)
Movement for the year	(4,725)	1,334
Unwinding of deferred tax on fair value uplift	(74)	(68)
Net DTA	**(5,174)**	**(375)**

The deferred tax balances are analysed below:

	2017 $'000	Movement $'000	2018 $'000	Movement $'000	2019 $'000
DTA					
Acquisition	(33,436)	--	(33,436)	--	(33,436)
Tax losses recognised	(34,293)	(1,794)	(36,087)	(3,389)	(39,476)
Tax losses derecognised	63,550	--	63,550	--	63,550
	(4,179)	**(1,794)**	**(5,973)**	**(3,389)**	**(9,362)**

DTL	2017 $'000	Movement $'000	2018 $'000	Movement $'000	2019 $'000
Accelerated tax depreciation	14,043	3,128	17,171	(1,337)	15,834
Non-current asset impairment	(33,214)	--	(33,214)	--	(33,214)
Acquisitions	19,580	--	19,580	--	19,580
Fair value uplift	2,129	(68)	2,061	(73)	1,988
	2,538	**3,060**	**5,598**	**(1,410)**	**4,188**

- DTA are recognised for tax loss carry-forwards to the extent that the realisation of the related tax benefit through future taxable profits are probable. DTA of $3.4 million have been recognised (2018: $1.8 million was recognised) based on future taxable profits over a 3 year outlook. The Group has unrecognised DTA amounting to $112.7 million (2018: $117.7 million) which have no expiry date.

- DTL have decreased by $1.4 million (2018: $3.1 million was recognised) as the temporary difference between the accounting values of property, plant and equipment and intangible assets and tax values decreased compared to 2018 year end.

- DTA and DTL can only be offset in the Consolidated 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).

17 Inventories

	Crude oil	Materials and supplies	Total
	$'000	**$'000**	**$'000**
At 1 January 2019	89	3,649	3,738
Impairment	--	(49)	(49)
Net inventory movement	--	1,454	1,454
At 31 December 2019	**89**	**5,054**	**5,143**
At 1 January 2018	130	3,636	3,766
Inventory movement	(41)	13	(28)
At 31 December 2018	**89**	**3,649**	**3,738**

(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.

18 Trade and Other Receivables

	Group		Company	
	2019	**2018**	**2019**	**2018**
	$'000	**$'000**	**$'000**	**$'000**
Due within 1 year				
Amounts due from related parties (Note 26 (d))	--	--	3,631	6,539
Trade receivables	5,307	10,408	--	--
Less: provision for impairment of trade receivables	(225)	--	--	--
Trade receivables – net	5,082	10,408	3,631	6,539
Prepayments	859	846	147	50
VAT recoverable	2,932	1,610	71	34
Other receivables	464	479	--	--
	9,337	**13,343**	**3,849**	**6,623**

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 Heritage/Petrotrin, a Provision matrix was completed to calculate a potential impairment on the receivable balances. Although all Heritage payments have been received on a timely basis, Petrotrin has long outstanding balances which give rise to a potential impairment. Consequently, a provision was calculated.

Trade receivables that are less than six months past due are not considered impaired and at 31 December 2019, trade receivables of $4.8 million (2018: $10.4 million) were therefore considered to be fully performing. At the end of 2018 a total of $6.7 million was outstanding from Petrotrin. During 2019 $6.2 million of this amount were received with a remaining balance of $0.5 million outstanding at the end of 2019. An ECL of $0.2 million was applied to the outstanding $0.5 million balance in the assessment of provision on the receivables amount. For Intercompany receivables an ECL of $0.1 million was calculated.

Ageing analysis of these trade receivables as at 31 December 2019 is as follows:

	2019 $'000	2018 $'000
Up to 30 days	4,491	7,616
>60 days	104	2,792
>180 days	712	--
	5,307	**10,408**

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

	Group		**Company**	
	2019 $'000	**2018 $'000**	**2019 $'000**	**2018 $'000**
USD	4,200	7,918	3,690	6,547
GBP	159	62	159	76
TTD	4,978	5,363	--	--
	9,337	**13,343**	**3,849**	**6,623**

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**	
	2019 $'000	**2018 $'000**	**2019 $'000**	**2018 $'000**
Trade receivables				
Counterparties without external credit rating:				
Existing customers with no defaults in the past	**9,337**	**10,408**	**--**	**--**

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

19 Cash and Cash Equivalents

	Group		**Company**	
	2019 $'000	**2018 $'000**	**2019 $'000**	**2018 $'000**
Cash and Cash equivalents	13,810	10,201	5,286	4,056
	13,810	**10,201**	**5,286**	**4,056**

Cash and Cash equivalents disclosed above and in the Consolidated Statement of Cash Flows exclude restricted cash and are available for general use by the Group.

20 Share Capital and Share Premium

Group

	Number of shares	**Ordinary shares $'000**	**Share premium $'000**	**Total $'000**
As at 1 January and 31 December 2019	**478,489,232**	**97,692**	**139,879**	**237,571**
As at 1 January 2018	377,199,972	96,676	125,362	222,038
Fully paid Issue of shares	101,649,260	1,016	14,517	15,533
As at 31 December 2018	**478,849,232**	**97,692**	**139,879**	**237,571**

- The Company does not have a limited amount of authorised share capital
- Within the Ordinary shares there are 94,799,986 deferred shares of USD 0.99 each totalling $93.9 million. The deferred shares have no voting or dividend rights and on a return of capital on a winding up, have no valuable economic rights

Year ended 31 December 2018	**Number of shares**	**Ordinary shares $'000**	**Deferred Shares $'000**	**Share premium $'000**	**Total $'000**
At 1 January 2018	377,199,972	2,824	93,852	125,362	222,038
New ordinary shares issued	101,649,260	1,016	--	--	1,016
Ordinary share premium	--	--	--	18,984	18,984
CLN discount	--	--	--	(3,265)	(3,265)
Cost of raising equity	--	--	--	(1,202)	(1,202)
At 31 December 2018	**478,849,232**	**3,840**	**93,852**	**139,879**	**237,571**

Note: $:GBP rate 1.312:1

21 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 share awards issued to employees
- The grant date fair value of deferred share awards granted to employees but not yet vested; and
- The issue of shares held by the Employee Share Trust to employees.

During 2019 the Group had in place share-based payment arrangements for its employees and Executive Directors, the LTIP. The Share Option Plan is fully vested and expensed. The current year charge through share based payments are in relation to the LTIP arrangements shown below, with further details of each scheme following:

	2019 $'000	**2018 $'000**
At 1 January	13,290	12,553
Share based payment expense:		
LTIP	1,038	737
At 31 December	**14,328**	**13,290**

Share Option Plan

Share Options were granted to Executive Directors and to selected employees. The exercise price of the granted option was 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. These Share Options were fully vested in 2015 and 2016 with nil exercised and expiry dates in 2022 and 2023. The table below gives details:

Grant-Vest	**Expiry Date**	**Exercise price per Share Options**	**2019 Number of Options**	**Exercise price per Share Options**	**2018 Number of Share 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

LTIP

LTIP awards are designed to provide long-term incentives for Executive Management 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.

2017 LTIPs

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 three 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 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.

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	GBp 10.75
Exercise price	GBP 0.00
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

2019 LTIPs

In January 2019 Options over 2,824,000 ordinary shares and in May 2019 Options over 3,832,824 ordinary shares were granted under the LTIP in accordance with the policy announced to the market on 25 August 2017. The 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 were 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.

The January 2019 LTIP awards will vest on 1 January 2021, while the May 2019 awards will vest on 2 January 2022 subject to meeting the performance criteria set out in the table below and continued employment with the Company. The Options are exercisable at nil cost by the participants.

Performance targets	**January 2019 LTIPs**	**May 2019 LTIPs**
Below the Median	None of the award will vest	None of the award will vest
Median (50th percentile)	30% of the maximum award will vest	30% of the maximum award will vest
Between Median and Upper Quartile	Straight-Line basis between these points	Straight-Line basis between these points
Upper Quartile (75%)	100% of the maximum award will vest	100% of the maximum award will vest
Above the Upper Quartile	100% of the maximum award will vest	100% of the maximum award will vest

The total fair value at grant date of the 2019 LTIP awards was $0.9 million and this will be expensed over the vesting period with the full charge pro-rated over the vesting period. The 2019 LTIP Awards are subject to the achievement of relative Total Shareholder Return ("TSR") performance targets measured over a 3-year performance period ending on 1 January 2021 and 31 December 2021 respectively. TSR is the increase in share price plus the value of any dividends paid over a period of time and captures the full return Shareholders see on an investment. Relative TSR is the comparison of these returns against peer companies over a set period of time.

The peer companies comparator Group has been created using the following filters:

- **Sector:** FTSE AIM All Share Oil & Gas constituents
- **Size:** Market capitalisation of between £20.0 million to £400.0 million
- **Further relevance filter:** Exploration & Production operations, excluding Oil equipment and services and Alternative energy

These filters create a comparator Group which excludes larger companies that may be expected to be on the main list and micro explorers that can show extreme volatility and which can be numerous at certain points in the business cycle. For 2018, the market cap range of £20.0 million to £400.0 million has been deemed appropriate, but the Remuneration Committee will review the appropriate range for each new LTIP grant.

The fair value at grant date was determined using 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 the 2019 LTIP awards granted during the period ended 31 December 2019 included:

	January 2019 LTIPs	**May 2019 LTIPs**
Grant Dates	2 January 2019	9 May 2019
Share price at grant dates	GBp16.77	GBp14.66
Exercise price	GBP0.00	GBP0.00
Expected volatility	113.9%	113.9%
Risk-free interest rates	0.73%	0.73%
Expected dividend yields	0%	0%
Vesting period	1 January 2021	2 January 2022

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

	2019 Average exercise price per Share Option	**Number of Options**	**2018 Average exercise price per Share Option**	**Number of Options**
At 1 January	GBP 0.00	25,415,998	GBP 0.00	25,415,998
Granted	GBP 0.00	6,656,824		--
Forfeited	GBP 0.00	(283,004)		--
At 31 December	GBP 0.00	31,789,818	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	2019	2018
2017 - 2022	2022	GBP 0.00	25,415,998	25,415,998
2019 - 2021	2023	GBP 0.00	2,824,000	
2019 - 2022	2024	GBP 0.00	3,549,820	

22 Merger and Reverse Acquisition Reserves

	Reverse Acquisition Reserve $'000	Merger Reserve $'000	Total $'000
At 1 January 2019	(89,268)	75,467	(13,801)
Movement	--	--	--
Translation differences	--	--	--
At 31 December 2019	**(89,268)**	**75,467**	**(13,801)**
At 1 January 2018	(89,268)	75,467	(13,801)
Movement	--	--	--
Translation differences	--	--	--
At 31 December 2018	**(89,268)**	**75,467**	**(13,801)**

The issue of shares by the Company as part of the reverse acquisition (February 2013) 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.

23 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 & PT for the period, adjusted for DD&A, ILFA, SOE, and Other Expenses (Non-Cash loss on oil price derivative financial 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:

	2019 $'000	2018 $'000
Operating Profit Before SPT & PT	10,271	6,720
DD&A	9,772	10,694
ILFA	608	--
SOE	1,038	737
FX (loss)/ gain	76	(17)
Other Expenses*: Loss on oil price derivative financial instruments	78	1,075
Adjusted EBITDA	21,843	19,209
	$'000	**$'000**
Weighted average ordinary shares outstanding - basic	384,049	330,579
Weighted average ordinary shares outstanding - diluted	415,840	355,995
	$	**$**
Adjusted EBITDA per share - basic	0.057	0.058
Adjusted EBITDA per share - diluted	0.053	0.054

Expenses totalled $ 0.08 million: Cash $0.06 million and Non-Cash $0.02 million

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

	2019 $'000	2018 $'000
Adjusted EBITDA	21,843	19,209
SPT	(7,413)	(7,050)
PT	(492)	607
Adjusted EBITDA After SPT & PT	13,938	12,766
	'000	'000
Weighted average ordinary shares outstanding - basic	384,049	330,579
Weighted average ordinary shares outstanding - diluted	415,840	355,995
	$	$
Adjusted EBITDA After SPT & PT per share - basic	0.036	0.039
Adjusted EBITDA After SPT & PT per share - diluted	0.034	0.036

24 Provision for Other Liabilities

(a) Non-current:

	Decommissioning provision $'000
Year ended 31 December 2019	
Opening amount as at 1 January 2019	41,802
Unwinding of discount (Note 8)	1,198
Increase in provisions for new wells	755
Revision to estimates	380
Decommissioning contribution	195
Translation differences	--
Closing balance at 31 December 2019	**44,330**
Year ended 31 December 2018	
Opening amount as at 1 January 2018	37,151
Unwinding of discount (Note 8)	1,557
Increase in provision for new wells	1,164
Revision to estimates	867
Decommissioning contribution	1,074
Translation differences	(11)
Closing balance at 31 December 2018	**41,802**

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 Heritage/Petrotrin 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% (2018: 2%)
b. Risk free rate – 2.13% - 3.07% (2018: 2.69% - 2.90%)
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.

(b) Current:

	Litigation claims $'000	Closure of Pits $'000	Total $'000
Year ended 31 December 2019			
Opening amount as at 1 January 2019	115	232	347
Decrease in provision	(69)	--	(69)
Increase in provision	--	240	240
Closing balance at 31 December 2019	**46**	**472**	**518**
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**

Litigation claims

In 2019 a litigation amount was settled for $0.0 million.

Closure of Pits

In 2019 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. It is an environmental regulatory requirement set by the Environmental Management Authority ("EMA") that all open drill pits for onshore drilling must be closed after sufficient testing has deemed it safe to close the pit. Testing period can last up to or over a year depending on the testing criteria.

25 Trade and Other Payables

	Group		Company	
Current	**2019 $'000**	**2018 $'000**	**2019 $'000**	**2018 $'000**
Trade payables	2,123	3,076	87	58
Accruals	5,039	3,454	421	423
Other payables	619	701	--	--
SPT & PT	2,605	1,916	--	--
	10,386	**9,147**	**508**	**481**

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 during the year. The following are the major transactions and balances with related parties:

(a) Sales of services and loans issued to subsidiaries

	Company	
	2019	2018
	$'000	$'000
Company subsidiaries:		
Trinity Exploration and Production Services (UK) Limited	(2,744)	3,176
Trinity Exploration & Production (UK) Limited	4	14
Trinity Exploration and Production (Galeota) Limited	120	13
Bayfield Energy Limited	29	14
Oilbelt Services Limited	(338)	1,197
Trinity Exploration and Production (Trinidad and Tobago) Limited	4	(501)
Galeota Oilfield Services Limited	3	--
Trinity Exploration and Production Services Limited	14	179
	(2,908)	**4,092**

There were no sales of services and loans issued to subsidiaries between the Group.

(b) Purchases of services: There were no purchases of services for Group nor Company.

(c) Key Management and Directors' compensation

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

	Group	
	2019	2018
	$'000	$'000
Salaries and short-term employee benefits	1,305	1,108
Post-employment benefits	41	33
Share-based payment expense (Note 21)	1,038	737
	2,384	**1,878**

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

	Company	
	2019	2018
	$'000	$'000
Receivables from related parties:		
Trinity Exploration and Production Services Limited	881	867
Trinity Exploration & Production (UK) Limited	18	14
Trinity Exploration and Production (Galeota) Limited	133	13
Bayfield Energy Limited	43	14
Oilbelt Services Limited	859	1,197
Galeota Oilfield Services Limited	4	--
Trinity Exploration and Production (Trinidad and Tobago) Limited	411	408
Trinity Exploration and Production Services (UK) Limited	1,282	4,026
	3,631	**6,539**

Group

- The receivables from related parties arise mainly from inter-group recharges. The receivables are unsecured and bear no interest. No provisions are held against receivables from related parties (2018: 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 Taxation Payable

	Group 2019 $'000	2018 $'000
Taxation payable		
PPT/ UL	80	--

28 Financial Instruments by Category

At 31 December 2019 and 2018, the Group held the following financial assets at amortised cost:

	Group		Company	
	2019 $'000	2018 $'000	2019 $'000	2018 $'000
Trade and other receivables – current*	5,546	10,887	147	6,623
Abandonment fund – non current	3,378	2,979	--	--
Cash and Cash equivalents	13,810	10,201	5,286	4,056
	22,734	**24,067**	**5,433**	**10,679**

Note (*): Excludes prepayments and VAT recoverable

At 31 December 2019 and 2018, the Group held the following financial liabilities at amortised cost:

	Group		Company	
	2019 $'000	2018 $'000	2019 $'000	2018 $'000
Accounts payable and accruals	10,386	9,147	508	481
Decommissioning	44,330	41,802	--	--
	54,716	**50,949**	**508**	**481**

At 31 December 2019 and 2018, the Group held the following financial liabilities at fair value:

	Group		Company	
	2019 $'000	2018 $'000	2019 $'000	2018 $'000
Derivative financial instrument	85	--	85	--
	85	**--**	**85**	**--**

29 Commitments and Contingencies

a) Commitments

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

The Group leases vehicles, offices and copiers under cancellable lease agreements. The lease terms are between once and five years, and the majority of lease agreements are renewable at the end of the lease period. Under IFRS 16, the leases are recognised as ROU Assets and Lease liabilities in the Consolidated Statement of Financial Position. From the aforementioned group of leases, the leases that did not fit the recognition criteria under IFRS 16 and was recognised in the Consolidated Statement of Comprehensive Income. The lease expenditure charged to the Consolidated Statement of Comprehensive Income during the year is as follows:

	Group 2019 $'000	2018 $'000
Not later than 1 year	--	139
Later than 1 year and no later than 5 years	5	21
	5	**160**

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 Marine Outer ("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 the twelve month period contingent upon specific clause within the Letter of Guarantee. The clause implies that Guarantor may reduce the Guarantee Sum available for payment to the MEEI under the Letter of Guarantee on an obligation by obligation basis provided PGB delivers to the Guarantor a certificate duly issued and signed by the MEEI.

iii) The Group is party to various claims and actions. Management has 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 Heritage/Petrotrin was established for due and punctual observance of the conditions, things and matters under the LOA effective until 31 December 2020. Non-performance to the terms of the LOA may result in the cash deposit being surrendered to Heritage/Petrotrin.

30 Employee Costs

Employee costs for the Group during the year	2019 $'000	2018 $'000
Wages and salaries	6,393	6,602
Other pension costs	342	633
Share based payment expense (Note 21)	1,038	737
	7,773	**7,972**

Average monthly number of people (including Executive and Non-Executive Directors') employed by the Group	2019 number	2018 number
Executive and Non-Executive Directors	7	6
Administrative staff	77	76
Operational staff	130	120
	214	**202**

31 Events after the Reporting Year

1. Hedging

The Company implemented two additional crude hedge options over the Group's monthly production on 3 January 2020 as follows:

Hedge	Floor	Cap	Strike Price	Production	Effective Date	Expiry Date
	$/bbl	*$/bbl*	*$/bbl*	*Monthly Barrels*		
3-way Option	50.0	56.0	65.5	12,500	1-Jan-20	31-Dec-20
3-way Option	50.0	56.0	65.5	12,500	1-Jul-20	31-Dec-20

2. Petrotrin Legacy Receipts

There remains an outstanding payment due from Petrotrin for October and November 2018 crude oil revenues, with an amount outstanding of $0.5 million at the end of 2019 for which an Expected Credit Losses ("ECL") of $0.2 million was recognised. The Group received $0.1 million of these delayed payments on 7 February 2020, with the remaining $0.4 million still outstanding.

3. COVID-19 Pandemic and Oil Price Decline

The impact of the COVID-19 virus on the demand for oil, and the inability of OPEC and Russia to agree sufficient supply curbs in a timely manner, has led to a significant decline in the oil price. WTI traded as high as $63.0/bbl in early January 2020, declining to $45.0/bbl as a result of reduced demand from COVID-19 in early March 2020, prior to the oil price war which subsequently drove prices lower than $20.0/bbl. On 12 April 2020, OPEC and Russia announced plans to reduce production output by nearly 10.0 mmbbls per day. However, concerns about storage capacity being exceeded led to oil-market history being made on 20 April 2020 when WTI prices dropped below zero for the first time (to minus $37.63/bbl). Although prices have since recovered somewhat, they remain below $30.0/bbl as at the last practicable date prior to approval of this announcement on 12 May 2020, and there remains considerable uncertainty regarding oil price levels during the remainder of 2020, and possibly beyond.

The World Health Organisation ("WHO") officially declared the COVID-19 as a pandemic on 11 March 2020. Effective 22 March 2020, the Government of the Republic of T&T ("GORTT") closed T&T's borders to all international and national travelers via the air bridge and sea ports. Subsequently, the operations of only essential services were approved by the GORTT (which includes oil and gas companies within T&T).

The COVID-19 pandemic's impact on demand for oil, the subsequent fall in oil prices, and the potential operating disruption to oil and gas companies is an extremely challenging and evolving situation. Given the fluidity and significant volatility of these events, it is extremely difficult to predict their impact on the Group at this stage as the oil price environment is dependent on the interplay between global demand and supply, both of which are changing significantly. Nevertheless, having assessed the current impact of these various factors, and the potential impact of a prolonged economic downturn triggered by the COVID-19 pandemic, the Directors currently believe the Group can maintain sufficient liquidity and a positive cash balance, and remain in operational existence, for at least the next twelve months (see Going Concern note 1)

4. CIBC Full Overdraft Credit Facility Drawdown

Trinity fully drew down its $2.7 million overdraft credit facility with CIBC effective 2 April 2020 as part of its strategy of maximising available cash during the short-medium term. The facility is a revolving overdraft credit available to Trinity which is repayable upon demand to CIBC. Interest is required to be paid monthly on the principal and currently attracts an interest rate charge of 2.7% (US Prime minus 6.3% per annum).