*This announcement contains inside information as stipulated under the UK version of the Market Abuse Regulation No 596/2014 which is part of English Law by virtue of the European (Withdrawal) Act 2018, as amended. On publication of this announcement via a Regulatory Information Service, this information is considered to be in the public domain.*

**Trinity Exploration & Production plc**
("Trinity" or "the Group" or "the Company")

**Final Results**

**Continued strong performance with structure in place for dynamic growth strategy**

Trinity, the independent E&P company focused on Trinidad and Tobago, announces its final results for the year ended 31 December 2021 ("the Period" or "FY 2021").

Trinity delivered another resilient performance in 2021. The Group is now positioned to leverage its cash and asset base to drive value and returns – with groundwork laid for near-term resumption of drilling, comprising a combination of high angle and horizontal as well as conventional low angle wells. This will be funded from existing cash resources and is the first phase of an ambitious growth strategy designed to maximise returns.

**Highlights**

- Revenues of USD 66.2 million (2020: USD 44.1 million)
- Average production of 3,069 bopd (2020: 3,232 bopd)
- Average price per barrel received increased to USD 60.4/bbl (2020: USD 37.7/bbl)
- Adjusted EBITDA of USD 19.8 million (2020: USD 12.1 million)
- Operating Profit* of USD 10.0 million (2020: USD 3.0 million)
- Sixth consecutive year of sub USD30.0/bbl operating break-even with industry wide cost pressures increasing
- Cash generated from continuing operations USD 12.6 million (2020: USD 10.3million)
- Cash flow used in investing activities USD 13.9 million (2020: USD 6.0 million)
- Year end cash USD 18.3 million (2020: USD 20.2 million)
- New 25-year Galeota Licence, Crude Sales Agreement, Joint Operating Agreement, Conversion to 100% Working Interest
- Lease Operatorship Agreements renewed for 10 years on attractive terms
- PS-4 acquisition completed - further enhancing Trinity's contiguous acreage

* Before SPT, PT, Impairments and Exceptional Items

**Positioned for Next Growth Phase**

- Dynamic strategy for growth is underpinned by a strong balance sheet and resilient and dependable cash flow
- Focus on maximising value from existing assets and through acquisitions and partnerships
- Clearly defined, risk-mitigated strategy to drive returns for shareholders through value growth and the potential to return cash
- Strengthened Board
    - Additions of Derek Hudson and Kaat Van Hecke further strengthening commercial, operational and wider industry skill sets
- Creation of Technical Committee
    - Focused on risk-mitigation and assurance of opportunities which can increase scale and optimise returns
    - Resumption of onshore drilling during H2 2022 is the first phase of this scaling up process
- Commenced planning for ambitious, risk-appropriate exploration programme
    - To test the remaining material prospective onshore resources, using 3D seismic to map leads with potential to be fast-tracked to monetisation
    - Exploring various options for the Galeota asset

**Post Period Highlights**

- Continued momentum into Q1 2022
    - Q1 production levels resilient with volumes averaging 3,013 bopd (Q4 2021: 3,103 bopd). 2022 average production will be influenced by the timing and outcomes of the drilling campaign.
    - Cash balance of USD 17.5 million as at 31 March 2022 (unaudited) (USD 18.3 million as at 31 December 2021)
    - Average realisation of USD 83.1/bbl for Q1 (Q1 2021: USD 52.3/bbl)
    - 2022 average production will be influenced by the timing and outcomes of the drilling campaign

**Analyst Briefing**

A briefing for Analysts will be held at 14.00 today both in person -– with Chairman Nicholas Clayton and Chief Executive Officer Jeremy Bridglalsingh and via web conference for those who are unable to attend. Analysts wishing to join should contact trinityexploration@walbrookpr.com.

**Investor Presentation**

The Company will be hosting a presentation through the digital platform Investor Meet Company at 16.00 today. Management will discuss results and the imminent drilling programme as well as longer-term opportunities. An updated investor slide deck will be added to the Company's website later today.

Investors can sign up to Investor Meet Company for free and add to meet Trinity Exploration via the following link https://www.investormeetcompany.com/trinity-exploration-production-plc/register-investor

**Jeremy Bridglalsingh, CEO of Trinity, commented: "***We are delighted with the Company's performance during 2021 and look forward with confidence. The reinforced technical guidance for the upcoming drilling programme points towards the potential for this to be an inflection point for the Company as we commence the next stage of our growth, and we very much look forward to updating the market with further developments in due course.*

*"Our ambition is to double production over the next few years, and thereby generate sufficient free cash flow both to fund future growth initiatives and deliver meaningful cash returns for shareholders, and we believe that we now have the structure in place to deliver this challenging target."*

***Enquiries***

For further information please visit www.trinityexploration.com or contact:

| | |
|---|---|
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**About Trinity** ( www.trinityexploration.com)

Trinity is an independent oil 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 the Group's 2P reserves as at the end of 2021 was 19.73 mmbbls. Group 2C contingent resources are estimated to be 47.22 mmbbls. The Group's overall 2P plus 2C volumes are therefore 66.95 mmbbls.

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

**CHAIRMAN'S STATEMENT**

It is a privilege to chair Trinity as we emerge from a period of significant change during which management refreshed our strategy and focused the business on clear and deliverable growth opportunities. Our dynamic strategy for growth is underpinned by a strong balance sheet and resilient and dependable cash flow from production - something of a rarity amongst the smaller companies in our sector - and a testament to our strong business model.

I would like to commend our team which has maintained focus, momentum and professionalism throughout a challenging year, allowing us to protect the integrity of existing assets and operate safely to deliver steady production and cash flow. Importantly, this core operating model provides the basis from which we can grow the Company into a leading independent producer of scale both by maximising value from existing assets and through acquisitions and partnerships. We have a clearly defined, risk-mitigated strategy in place and believe that this will drive returns for shareholders through value growth and the potential to return cash.

At time of publishing, the world is in turmoil and we are deeply concerned for those most affected by hostilities in the Ukraine. This global upheaval brings with it a raft of new and different challenges to an industry already coping with the perfect storm of restrictions on working practices imposed by the Covid-19 pandemic, unprecedented volatility in commodity prices and, in our own case, the shock of the sudden and untimely passing of our founder and Executive Chairman, Bruce Dingwall, CBE. As such, 2021 proved to be an extraordinarily difficult year to navigate, but one in which Trinity proved its resilience and, perhaps as importantly, its ability to act decisively for the benefit of our stakeholders, refining and prioritising our extensive opportunity set, with a view to generating significant growth in value in the relatively near term.

**Board Changes**

In the past year we have changed the composition of our Board to bring Trinity's governance structure more in-line with market practice, with the role of Chairman becoming a non-executive position, complimented by the promotion of Jeremy Bridglalsingh to the position of Chief Executive Officer. Jeremy is a Trinidadian whose contribution to the Company's strategy and development since becoming CFO in 2016, and more recently Managing Director in 2019, cannot be underestimated.

Further, we added depth and breadth to an already strong Board, welcoming two important new non-executive directors, Derek Hudson and Kaat Van Hecke, both highly respected and experienced members of the international energy industry. David Segel stood down from the board in March 2021, and I would like to place on record my thanks for his invaluable contribution to our deliberations since he joined the board following our recapitalisation in 2016.

**Technical Committee**

Trinity fields an expert sub-surface team whose knowledge of the geology of Trinidad's hydrocarbon-bearing basins is a core strength of the Company. To support them and assist the Board by bringing a global context to analysis of potential new projects, during 2021 we established an external advisory committee of world-class sub-surface and petroleum engineering experts who will help us to critique and filter prospects so that we can confidently focus expertise, energies and investment to fast-track only the most viable, high-grade opportunities.

The Technical Committee comprises two board members and three high-quality independent experts and has helped management refine and prioritise its existing opportunity set to focus on risk-mitigated prospects capable of being delivered with the Company's existing financial and operational resources to increase scale and optimise returns. It has set ambitious but deliverable growth targets, and the resumption of onshore drilling during the second half of this year is the first part of this scaling up process.

**Managing risk to deliver growth in production and cash flow**

This additional layer of uncompromising, qualitative analysis in geoscience and petroleum engineering is matched by two of Trinity's key financial characteristics; capital discipline, with an increasing focus on risk assessment, and a relentless commitment to cost management. 2021 saw Trinity turn in its sixth consecutive year of sub USD 30.0/bbl operating break-even, in fact USD 29.2/bbl, a real achievement in such challenging times and an excellent discipline to provide a buffer against times of low market prices. The Company expects an increase on the usual operating breakeven in FY 2022 to support medium term growth through increased technical and intellectual capacity and with industry-wide cost pressures increasing.

Furthermore, Trinity maintains a strong balance sheet, with cash resources of USD 18.3 million at 31 December 2021 (2020: USD 20.2 million), meaning we have the resources we require to deliver our near term growth objectives.

These pillars of our business culture will underpin our dynamic future strategy where we aim to grow our predictable, stable production and cash-flow allowing us the opportunity to both fund attractive new growth opportunities and deliver cash returns to shareholders.

**Risk-appropriate investment for future growth**
Stable cashflow forms the bedrock of Trinity's financial strength and positions us well for our next, exciting growth phase. One of our key operational objectives is to safely and sustainably build and scale production and we have already commenced planning for an ambitious, risk-appropriate exploration programme that will tap into the region's material remaining reserves, using 3D seismic to map prospects with potential to be fast-tracked to monetisation, generating material growth for our shareholders whilst understanding and hopefully ameliorating technical and commercial risk.

An additional layer of potential comes from the ongoing farm-down process for our Galeota licence, comprising the producing Trintes field, the Echo Prospect and potential from the Foxtrot and Golf accumulations. The Company has engaged with a range of potential partners and whilst initial feedback has been encouraging, several participants have indicated their inability to fully assess the economics of the opportunity without clarity being considered by the Government of Trinidad and Tobago ("GORTT"). As these considerations seem to have been delayed, and to ensure that the Company attains the best possible value proposition for this highly valued asset, we have made the decision to pause our farm-down process until the GORTT fiscal reforms have been concluded.

We continue to explore a variety of options for this asset, with the aim of maintaining exposure while avoiding the need for material additional debt or diluting existing shareholders. These key criteria must be met, together with tax reform in Trinidad, which has been flagged by the Government, before your Board will commit to/progress any partnership offers.

We eagerly anticipate T&T's new bidding rounds for exploration blocks both onshore and near offshore. We will target licences that provide additional opportunities to expand our footprint in Trinidad. Concurrent with that, we will continue to evaluate acquisition opportunities.

**Investing in future energy and transition**
Unfolding geopolitical events have made it clear that, for many years to come, 'traditional' energy (i.e. oil & gas) will remain an essential part of the energy mix. However, the clock is ticking towards Energy Transition & Net Zero and Trinity's goal is to be at the forefront of T&T and the wider Caribbean region's energy transition.

During 2021 we established a new senior executive role of Innovation, supported by a small but highly qualified team, and have already instigated several meaningful studies and ground-breaking collaborations that we believe will challenge conventional thought and help to develop innovative new approaches to energy production.

Trinity's ESG programme is designed to build environmental considerations into the mindsets of our people and the heart of our business culture such that sustainability becomes one of the cornerstones of our future vision.

**Financial Discipline**
Our 2021 results demonstrate your Company's resilience. Adjusted EBITDA for the year was USD 19.8 million (2020: USD12.1 million) and cash resources were USD 18.3 million (2020: USD 20.2 million) at year end despite the absence of new drilling activity. In 2021, in line with previous years, we hedged around 50% of our production to counteract the impact of low oil prices and the effects of Supplemental Petroleum Tax ("SPT"), which is at its most punitive when realised oil prices are between USD 50.01 and USD 55.0 per barrel. The adoption of a similar

policy for 2022 has significantly reduced the immediate benefit of high oil prices on our profitability and cashflow, especially in the first half of the year. However, we expect the impact will decrease in H2 2022, as a lower proportion of our existing production is hedged and our onshore drilling programme will bring new production onstream.

**Financial restructuring**
At an appropriate future point it is our goal to make returns to shareholders either in the form of cash dividends or share buy-backs. With this in mind, during 2021, your Board undertook a complex share capital re-organisation to position the distributable reserves at PLC level that will enable us to return cash to shareholders as and when appropriate.

**Fiscal Reform**
Throughout 2021 Trinity continued to leverage its deep and long-standing relationships with Government, Heritage and the region's energy participants more broadly to make the case for positive fiscal reform. We remain confident that the Government understands the requirement for fiscal reform, despite the near-term outlook for crude oil prices, in order to stimulate investment and development of the country's oil and gas resources, to the benefit of all T&T stakeholders. We understand that the Government's deliberations on tax reform, specifically in relation to SPT, are ongoing, and we look forward with keen interest to receiving positive news on this matter in the near term.

**Thanks**
I would like to conclude by extending the thanks of the Board to our Shareholders who have remained supportive and engaged despite a difficult year. As the frustrating limitations imposed by the Covid-19 pandemic hopefully subside we look forward to engaging 'in-situ' with shareholders and our broader stakeholder community with plans for a busy agenda of presentations and events throughout the coming year. I would also like to extend the sincere thanks of the Board to our management and employees whose unstinting dedication has allowed us to successfully and safely navigate the challenges posed by the Covid-19 pandemic.

We entered 2022 with a refreshed strategy, a strong balance sheet and a dynamic vision for growth. We believe the time is right for Trinity and are energised to deliver optimum value on your behalf.

Nicholas Clayton
Non-Executive Chairman

## CHIEF EXECUTIVE OFFICER'S REVIEW OF 2021

The sudden and unexpected passing of our founder and Executive Chairman, Bruce Dingwall, in August 2021, has accelerated our plans to focus the business, building on the strong foundations he had built to take Trinity into a new and dynamic growth phase.

In this context, I am extremely proud to be leading a strongly bonded, talented team of hard-working individuals who have consistently brought their top game to bear throughout the year, enabling Trinity to deliver an applaudably resilient performance in challenging circumstances.

**Growth Strategy**

We believe that this is an inflection point for the Company with the imminent resumption of drilling commencing the next stage of our growth. During the past year we have re-focused, prioritising Trinity's existing opportunity set to focus on risk-mitigated prospects capable of being delivered with the Company's existing financial and operational resources to increase scale and optimise returns. In addition, we now have the expertise and processes in place to mitigate risk and appropriately prioritise the various opportunities we continue to consider.

This rigorous approach has resulted in the Company de-selecting some options, a signal of the important contribution of our Technical Committee's mentorship and guidance. The level of commercial and operational input their experience brings is now enabling us to shape our decision-making process by adding quality reviews alongside technical risk assurance of the options we are pursuing.

Whilst we are focused on expanding our portfolio we will not put undue pressure on the Company's cash and operational resources. We are now positioned to activate our refined strategy with a view to driving value. Our ambition is to double production over the next few years, and thereby generate sufficient free cash flow both to fund future growth initiatives and deliver meaningful cash returns for shareholders. And we believe we now have the operational and financial resources we need to deliver this challenging target.

**Financial Performance**

Following a difficult year in 2020, when commodity prices dipped dramatically and Trinity's average price received was USD 37.7/bbl, we welcomed the market's recovery and the subsequent uplift in our realised price for 2021 to USD 60.4/bbl. The combined effects of this uplift and our relentless pursuit of cost efficiencies delivered an adjusted EBITDA of USD 19.8 million (2020: USD 12.1 million) and ending cash of USD 18.3 million after meaningful capex invested of USD 13.9 million (2020: USD 6.0 million)

Our hedging policy has historically been designed to provide protection from low commodity prices and to ameliorate the impact of realised prices in the USD 50-55/bbl range where SPT in Trinidad is most punitive. In the context of the recent extraordinary and unpredictable uplift in commodity prices, magnified by Russia's invasion of Ukraine in March 2022, we are not alone in finding that our hedges have blunted the otherwise positive impact these higher prices would have had on our operating cashflow. We expect the impact will decrease in H2 2022, as a lower proportion of our existing production is hedged and our onshore drilling programme will bring new production onstream. Going forward, we expect that growing our onshore production, further driving down our operating break-even, and the expected reform of the SPT regime will significantly reduce our future hedging requirements.

**HSSE**

My first priority is the health and safety of our workforce and contractors as well as minimising the environmental impact associated with our operations. However, while our leading indicators continue on a favourable trajectory, we incurred three Lost Time Incidents ("LTIs") during 2021. This has prompted us to place even greater emphasis on HSE throughout the organisation, from the Boardroom to the well head. We have created an HSE Steering Committee, and have also appointed an HSSE champion at Board level, Kaat Van Hecke, to oversee this function and highlight its critical importance to us as a company. This has begun to inject greater rigour into our HSE oversight, with a prime focus on creating Trinity's Safety Rules to underpin our safe systems of work.

I am delighted to chair the HSE Steering Committee and the energy and enthusiasm of those involved is helping to drive improvements in the effectiveness of our HSE function. This will further strengthen our operations, motivate our team and demonstrate to our partners and regulatory stakeholders our competency as an operator.

**OPERATIONS IN 2021**

**Reducing Volatility**

During 2021, having taken a commercial decision not to recommence drilling activity, we opted to underpin our base production via a programme of seven recompletions, 96 workovers and increasing the volume under surveillance via Supervisory Control And Data Acquisition ("SCADA") to ~50% of total production. The impact of these activities, allowing us to increase the predictability of our production profile and mitigate natural reservoir decline for the second consecutive year, has been significant. Despite the absence of drilling, production for the year reached the upper quartile of our guidance (2,900-3100 bopd), averaging 3,069 bopd, slightly lower than 2020's 3,232 bopd.

In particular, our strategic decision to invest in technology to automate and optimise our wells has proved to be highly effective. The operation of 31 Tier 1 onshore wells, over half of all Trinity's production, is now automated, helping to ensure steady, low-cost production whilst minimising non-productive downtime. As a result, 2021 saw Trinity deliver its sixth consecutive year of sub-USD 30.0/bbl operating break-even, a real achievement in such challenging times and an effective buffer against times of low market prices. Shareholders will see a small upward shift in our breakeven to low USD30's in 2022 as we increase the intellectual resource to achieve our medium term vision of scaling up Trinity, but our relentless focus on optimising production and reducing cost continues.

Trinity is already one of T&T's top five crude oil producers, giving us a deep historical knowledge of the region's hydrocarbon basins and strong working relationships with our partners and regulatory stakeholder. The benefit of this unique skillset came to the fore during 2021 when our Field Development Plan ("FDP") for Galeota attained full Ministry approval within just three months, an unusually short timeframe and testament to the quality of our technical rationale. This was aided by the timely acquisition of the full suite of Certificates of Environmental Clearances for Galeota's Echo project from the Environmental Management Authority.

In line with our strategy to refine and prioritise the range of growth options at our disposal, our sub-surface team, supported by world class external consultants, continued their study of the 37 km2 of 3D seismic acquired during 2021 from Heritage Petroleum Company Limited ("Heritage"). This activity was significantly complemented by gaining access to the entire 287 km2 3D seismic data made available via our participation in the NWD process.

The Technical Team continues to work hard to accelerate its interpretation and integration of this data to enable Trinity to develop a regional geological framework with a view to identifying new play concepts, deeper, largely undrilled reservoirs, and the best locations for drilling into the key productive Forest and Upper Cruze horizons, being the dominant producing reservoirs onshore Southern Trinidad.

Our principal objective is to improve our drilling returns by developing a mix of lower risk, conventional wells, with technically more challenging but potentially higher return, high angle, horizontal and deeper wells. These more complex wells have the potential to increase the ratio of barrels recovered to the capital invested, and thereby provide stronger economics.

**Growth through acquisition and collaboration**

The Company is in robust financial health, and is conservatively financed compared with many of our peers, where operating break-evens are higher and finances more constrained. We are therefore well placed to take advantage of commercial opportunities as and when they arise. A prime example of this was our acquisition of the PS-4 Block Lease Operatorship Sub-Licence, onshore Trinidad, which was finalised in December 2021. We moved quickly to secure this synergistic asset, adjacent to our core WD5/6 and WD2 producing assets, funding this acquisition out of existing cash resources.

To progress some of the exciting opportunities in the T&T region Trinity continues to develop excellent working relationships with potential partners, both Heritage (the state-owned oil company) and larger international operators.

Reviewing opportunities for growth, we consistently apply rigorous technical and financial metrics to balance risk with reward. In this context, having carefully appraised the NWD exploration play in Trinidad's Southern Basin with partner Capricorn Energy PLC, the Board decided not to participate further with this process as neither we nor our partner Capricorn Energy were comfortable with the technical and operational risks associated with the deeper Cretaceous leads that were identified.

**GALEOTA**

Our Galeota prospect offers a broad range of opportunities to add value for Trinity

- The Trintes field, currently producing at 1,107 bopd, in which the significant 2P reserve potential has not been fully exploited,
- The Echo Prospect, which has an approved FDP, with potential peak production of 7,000 bopd
- The Foxtrot and Golf appraisal prospects with combined peak production of 7,000 bopd
- Significant tax losses of circa USD164 million

**A crucial milestone**

In July 2021 our negotiations with the Ministry of Energy and Energy Industries ("MEEI") and state oil company Heritage were rewarded with the award of new and improved commercial terms including

- A new 25-year licence commencing 14 July 2021, covering an area of 19,280 acres
- A significant reduction in minimum work obligations and performance guarantees
- A new Crude Oil Sales Agreement ("COSA") provides greater pricing clarity
- An improved Joint Operating Agreement ("JOA") more aligned with international standards

One of the outcomes of this development is that Management's estimate of the net 2P plus 2C reserves increased to 50.16 mmbbls (previously 27.60 mmbbls). An additional benefit is the conversion of Heritage's 35% working interest to an Overriding Royalty ("ORR") whereby the Company now benefits from holding a 100% Working Interest over the entire block, enabling Trinity to apply the bulk of its tax losses across the entire Galeota Licence area.

These improved terms provide Trinity and prospective funding partners with more attractive commercial terms and the requisite visibility to bring on new low carbon development projects such as Echo, incentivising maximum resource extraction at a time of high oil prices and a transition towards lower carbon intensity energy supplied.

The Galeota farm-down process got underway in December 2021, hosted by Stellar Energy Advisers, and whilst initial feedback has been encouraging, participants were unable to fully assess the economic opportunities at Galeota without clarity on expected SPT reform. On this basis the Company has decided to pause the Galeota farm down process pending SPT reform. This will enable the Company to seek the best value proposition for Galeota. In keeping with our prudent commercial strategy, Trinity is working hard to achieve the most capital efficient outcome, balancing acceptable and proportionate levels of investment with a desire to maintain a significant share in the project and thus our ability to deliver significant upside for shareholders.

**Sub Licence Renewals**

We were delighted that Heritage reconfirmed their trust in Trinity's skills and commitment by extending five of the Company's six Lease Operatorship Agreements ("LOAs") for an additional 10 years, effective 1 January 2021, on improved commercial terms. This will allow Trinity to plan and commit to future work programmes across its onshore assets with greater confidence.

**New Exploration Licences**

In response to the recent announcement made by the T&T Government of its intention to conduct new onshore, shallow water and deep offshore bidding rounds, Trinity has registered non-binding interest in six onshore blocks. Details of the shallow water blocks have not yet been released. We anticipate that further details will become available following announcements relating to fiscal reform, which we consider to be essential to the success of the bid rounds.

**Fiscal Reform**

We remain optimistic about the prospects for imminent, and necessary, reform of T&T's fiscal regime, specifically SPT which significantly discourages investment and stifles activity in the sector. This is, in our view, essential if Trinidad is to attract the necessary investment to maximise the value of its world class hydrocarbon deposits within the Net Zero time frame. We continue to work with the MEEI and wider Government with the goal of delivering a positive outcome.

**Our ESG Activities**
In 2021 a structured and focused approach has been initiated towards our ESG Programme as we position Trinity on a trajectory to deliver a sustainable future for your Company. The measurement and reporting of environmental performance is an emerging science and Trinity is taking the important steps to understand what is required and to ensure that what we measure and report is transparent, provable and, most importantly contributes positively to sustainable operations in years to come.

In Q4 2021 we appointed an expert external advisory team to help us refine our ESG strategy and develop a clear process by which ESG becomes embedded across the business. They have hosted several well-attended workshops including both office and field-based staff, tailor-made to explain the regulation framework in the context of our own operations and provide ongoing guidance on the necessary changes to our work methods to ensure that the data we report is reliable. Internally, an ESG Committee was established and a new senior post of Executive Manager, Innovation was created along with an Innovation Team.

With regard to the Social element of ESG, our HR and Business Administration Teams have been pro-active in enhancing our healthcare provision, devising wellness programmes and ramping up our community engagement to provide much needed support for school children and families. In collaboration with the University of West Indies ("UWI") a scholarship fund in our recently deceased Bruce Dingwall's name has been established.

Our Chairman has already alluded to changes made to our Board to upgrade our governance model and we are delighted to have welcomed two new members, one of whom, Kaat Van Hecke, brings specific expertise and focus on HSSE matters.

**Renewables**
Momentum in energy efficiency and transition to renewable energy is picking up. We believe that in the medium term there may be renewable power opportunities with the potential to be accretive to shareholder value. For that reason, Trinity is building a strong network of partners to ensure that our Company is part of the vanguard leading T&T's commercialisation of emerging renewable technology.

We are delighted to continue to develop these important relationships, helping to explore and develop new projects with the National Gas Company ("NGC") and the UWI. The scope of their mission is to enable energy transition not only in T&T, but potentially in the wider Caribbean and Latin America. We have no doubt that a number of innovative projects will come out of this important collaboration which is already bearing fruit with:

- Commencement of T&T's inaugural Solar irradiance study adjacent to Trinity's Galeota field office, with plans for a further Wind Resource Assessment
- Installation of a solar power system for the WD5/6 field office

In summary, 2022 marks the start of a planned growth phase for Trinity; a robust operating platform, a refreshed Board, further complemented by the formation of a world-class technical advisory committee, a refined strategy and a healthy balance sheet all put Trinity in an ideal position to accelerate growth and generate meaningful returns for shareholders.

Jeremy Bridglalsingh
Chief Executive Officer

**OPERATIONS REVIEW**

In the face of a year dominated by lockdown and Covid-19 restrictions, a decision was made to desist from any new drilling within our portfolio, meaning that Group production for 2021 aligned with natural reservoir decline of ~7%. As we weathered the pandemic we were forced to adapt our operating plans to achieve the budgeted level of production and with production growing by 4% from Q3 to Q4 we exited 2021 at 3,143 bopd. This has provided us with a stable platform entering 2022.

Current onshore production is from Lease Operatorship Blocks: WD-5/6, WD-2, FZ-2, WD-14, WD-13, PS-4 and Farmout Block, Tabaquite.

Average 2021 net sales from the onshore assets was 1,644 bopd (2020: 1,793 bopd), which accounted for 55% of total annual average sales. The projections for the year anticipated this decline since no drilling was planned. The team's multi-faceted approach to production delivery included recompletions ("RCPs"), work-overs ("WOs"), reactivations, sand exclusions, an expanded swab portfolio and production optimisation initiatives to maintain production delivery.

Trinity executed 7 RCPs Onshore during the year (2020: 16) as well as 74 WOs (2020: 92), and 5 sand control jobs (2020:2).

Overall, we aim to minimise the need for well interventions, and reduce the frequency of WOs, as we target an increasingly predictable and sustainable production base. Timely execution of WOs when they are required is an essential component of our strategy, in returning base wells to production as quickly as possible. Our sand control measures focused on high frequency wells impacted by formation entry. As described below, the combination of surveillance and automation further assisted in our ability to improve our response to our Tier 1 ( > 25 bopd) wells on which they were installed in WD-5/6.

Natural annual field decline of 7-10% can be significantly mitigated via the execution of RCPs and, in spite of a slow approval process (within Heritage and the Government) due to Covid-19, our campaign delivered substantially all of the intended production targeted from the RCP programme.

In 2022, the team intends to explore further cost-effective means of production maintenance through the expansion of the active well stock via RCPs, reactivations and swabbing.

**Automation continues to enhance efficiency**

Trinity's use of automation to optimise our production uptime took a significant step forward in 2021, with the execution of the automation of 31 Top Tier wells that covers 85% of the Block production in WD-5/6, which has delivered some preliminary results:

- 11 WOs have been avoided during the period due to remote surveillance by the SCADA monitoring team
- Real time data collection through the SCADA system is facilitating faster responses to changing well conditions and optimised real time production. Speed ramp up and pump stroke optimization in real time netted > 3000 bbls increased production.
- Reduction in Man Hours required for production and monitoring.
- Carbon footprint has been reduced by having less frequent wellsite visits and fewer WOs.

Further works are being progressed to building internal competency and leveraging more cost-effective automation that can be deployed on lower producing wells.

**East Coast Assets**

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

Average 2021 net sales from the East Coast were 1,107 bopd (2020: 1,188) accounting for 37% of the Group's total sales broadly in line with 2020. To achieve this, the team conducted 15 restorative WOs (2020: 16) including

1 well reactivation to underpin production (2020: 4 well reactivations) and 2 electrical submersible pump ("ESP") WOs were conducted (2020: 1 ESP WO), with continuous emphasis being placed on optimisation and stabilisation of all wells via a data driven strategy utilising automation. An enhanced chemical injection strategy was executed to counteract increased solids deposition in the mature wells.

Again, our ongoing approach of digitalising the Trintes field to provide reliable and informative essential data in relation to the wells, thereby pre-empting potential issues and problems, allowed us to stabilise production. The result is an ongoing reduction in the production fluctuations in the field brought about by proactively predicting possible failures and effectively developing mitigation plans. These production focused operations were coupled with the team's ongoing efforts to maintain the integrity of our mature offshore assets. This process is ongoing and is expected to further improve the team's ability to execute essential workplans safely.

**Galeota Asset Development (Trinity: 100% WI)**

The TGAL discovery area (proposed Echo hub) lies in the Galeota Licence and sits within a separate Fault Block (mapped as Fault Block 6), an updip panel located to the northeast of the Trintes Field, confirmed as being oil bearing in six major stacked reservoir horizons by the TGAL-1 exploration well with an internal best estimate STOIIP of 187.5 mmstb. Trinity received FDP approval for the Echo Development from the Ministry of Energy and Energy Industries ("MEEI") in November 2021. The approved FDP proposed a conservative eight well configuration. Both the MEEI and reserve auditor, NSAI, have indicated that the current approved FDP Case leaves considerable upside potential for recoverable hydrocarbons with an increased number of well slots. On this basis, Trinity has considered a variety of development cases to maximise the recoverable hydrocarbons from the Echo Development. Trinity's preferred development case (Most Likely Case) consists of an Echo twelve well configuration. This aligns with MEEI's FDP and NSAI 2021 CPR recommendations and strategy to accelerate the development and production of its remaining oil and gas reserves in the time available during the energy transition.

The Most Likely Case, a 12 well configuration may be adopted and will not only target TGAL but also additional proven oil and reservoir sands from the adjacent Trintes fault blocks FB4 and FB5; targeting recoverable resources of 25.2 mmbbls with peak annualised production of 6,977 bopd, approximately one year after first oil.

Works on various pre-FEED studies to improve the topside and other aspects of the facilities design was completed in 2021. In addition, subsurface model building to support dynamic reservoir simulation for forecasting production performance and cumulative estimated ultimate recoverable (EUR) volumes were completed in 2021. The Environmental Impact Assessment ("EIA") is a key item on the critical path to Final Investment Decision ("FID") which was submitted in February 2021 and represented a significant milestone. The Certificate of Environmental Clearance was granted in February 2022. Other key milestones achieved in 2021 included the conversion of the working interest in the Galeota block from 65% to 100% and attaining FDP approval from MEEI

In Q4 2021, the Company commenced a formal marketing process for a farm-down of the GAD Project and has appointed Stellar Energy Advisors as its advisor for the divestment.

There is potential for the GAD Project, which encompasses the Trintes Field's current production, the Echo Field Development and the Foxtrot and Golf appraisal areas, to significantly change the scale of Trinity's operations. As previously announced, the combined 2P reserves and 2C/2U resources from these fields exceeds 50 mmbbls, with dynamic modelling indicating peak annualised production of circa 7,000 bopd from Echo alone. An Independent Competent Person's Report on these assets was completed in Q4 2021 by Netherland, Sewell & Associates, Inc., which offers significant support to Trinity's own internal volumetric assessment of the Galeota Block.

The Company has engaged with a range of potential partners as part of the Galeota farm down process. Whilst initial feedback has been encouraging, a number of participants have informed the Company that they are unable to fully assess the economics of the opportunity at Galeota without clarity on the expected reforms to Supplemental Petroleum Tax ("SPT"), which are currently being considered by the Government of Trinidad and Tobago ("GORTT") and which were initially expected to have been confirmed sooner than now appears likely.

Pending SPT reform, which management still expects to happen, the Company has decided to pause the Galeota farm down process. This will enable the Company to seek the best value proposition for Galeota when the GORTT's fiscal reforms have been confirmed.

**West Coast Assets**

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

Average 2021 net sales from the West coast was 255 bopd (2020: 245 bopd) which accounted for 8% of the Group's total annual average sales and a 4% increase from 2020 average. This increase was achieved by continuing infrastructural initiatives coupled with the production enhancing project to arrest the decline from the West Coast assets.

The team remains focused on exploring opportunities to optimise production from all offshore platforms in this asset. No RCPs (2020: 0) were conducted, however two WOs were completed in the PGB asset for the period.

BM asset sales experienced a 17% increase to 155 bopd (2020: 133 bopd). This was achieved by the team implementing a number of rigless production enhancing initiatives. No WOs or RCPs were conducted during this period (2020: 2 RCPs and 1 WO).

The team remains focused on improving asset integrity on its offshore platforms to create a safer working environment and ensure production is maintained. We continue to evaluate additional initiatives to extend the operations horizon by increased WO, RCP and swabbing activity.

**Facilities Management and Infrastructure**

In 2021, the Facilities team paid particular attention to upgrading production and the welfare infrastructure on its East Coast Trintes Field and addressed key integrity challenges in relation to the West Coast Brighton Marine Field. These marine installations require a higher level of maintenance due to the harsher East/West Coast offshore environment. The internal team was supplemented by the recruitment of highly experienced contractors, mechanics and electricians, to ensure a higher level of operational reliability and uptime on the assets at lower cost.

In 2021, the Team focused on structural and operational reliability, as such, we progressed 36 projects of which 23 were completed and 13 rolled over in 2022.

One key activity is the construction of the new 10,000 bbls storge tank to service the Trintes field. This experienced some delays as a result of inclement weather and Covid-19 related issues. However, the works have resumed, with an anticipated completion during Q3 2022. This tank will bring additional storage capacity and operational flexibility to the Trintes operations ensuring tank certification compliance without any disruption to production.

Facilities Management and Infrastructure spend in 2021 totaled USD 3.2mm.

**Reserves and Resources**

A comprehensive management review of all assets has been concluded and has estimated Trinity current 2P reserves to be 19.73 mmstb at the end of 2021, compared to the year-end 2020 reserve estimate of 19.55 mmstb. This represents a 0.9% year-on-year increase. The overall increase in reserves of 0.18 mmstb results from a combination of both negative and positive influences on oil volumes across all assets. However, a Reserves Replacement Ratio (RRR) of 100% was achieved in 2021 with production of 1.10 mmstb fully replaced together with updated well numbers and decline curve analysis on planned infill and producing wells Onshore and Offshore the West and East Coast.

Brent Forward Price Deck applied to Reserves Economic Limit Testing ("ELT") as at 3 January 2022

WTI Forward Price Deck applied to Reserves Economic Limit Testing ("ELT") from Britannic Trading LLC as at 3 January 2022

| (USD/ bbl) | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|
| Price Strip | 76.48 | 71.76 | 68.91 | 67.09 | 65.97 | 65.25 | 65.65 | 65.65 |

Management considers the reserves presented in the table below represent the best estimate as at 31 December 2021 of the quantity of reserves that will actually be recovered from our current 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 these reserves as detailed by asset area shown in the table:

Unaudited 2021 2P Reserves

| Net Oil Production | 31 December 2020 mmstb | Production mmstb | Revisions mmstb | 31 December 2021 mmstb |
|---|---|---|---|---|
| Onshore | 5.44 | (0.60) | 2.42 | 7.26 |
| East Coast | 11.66 | (0.40) | (1.48) | 9.77 |
| West Coast | 2.45 | (0.09) | 0.33 | 2.70 |
| Total | 19.55 | (1.09) | 1.27 | 19.73 |

Note (*):

–

East Coast 2P reserves decreased due to a reclassification of three Trintes infill wells to horizontal well targets for Echo (-1.89MMstb) which was partially offset by the impact of wells optimisation and maintenance and economic limit testing improvements (+0.4 MMstb)

Onshore and West Coast 2P reserve changes primarily reflect ongoing well optimisation across all assets to arrest decline from our base wells and, for the Onshore, the acquisition of PS4 adding 2P reserves of 0.67MMstb

The planned 2022 onshore drilling campaign, comprising a combination of high angle and horizontal wells, conventional wells and more materially, stratigraphically untested deeper reservoirs within the fields have utilised improved performance prediction methods (ie dynamic simulation, inflow equations etc) and decline curve analysis for assurance in forecast predictions.

Management's best estimate of 2C resources as at 31 December 2021 is 47.22 mmstb (2020: 23.25 mmstb). The positive movement of 23.97 mmstb in 2C resources primarily reflects our increased working interest in Galeota, now 100% compared to 65% at YE 2020 following the successful revision of the license terms.

Management's Estimate of 2C Resources as at 31 December 2021

| Asset | 31 December 2020 mmstb | Revisions mmstb | 31 December 2021 mmstb |
|---|---|---|---|
| Onshore | 4.01 | (0.19) | 3.82 |
| East Coast | 15.94 | 24.45 | 40.39 |
| West Coast | 3.30 | (0.29) | 3.01 |
| Total | 23.25 | 23.97 | 47.22 |

Note (*):

- East Coast:
  - Working interest in Galeota is now 100% compared to 65% used in YE 2020
  - Year End 2020 ECHO FDP conservative 8 well development vs. Year End 2021 most likely Case of 12-well development inclusive of re-categorization of three Trintes infills now being carried as 2C at ECHO

    - Additional contingent resources for the shallower TGAL G, H, and M Reservoirs, which are not targeted for initial TGAL (Echo) development, but forms part of phased future development plans.
- Onshore:
    - Base Production Optimisation Operations to recategorize some 2C to 2P
    - Improved Well Decline Analysis on planned 2P infills to capture more 2C;
- West Coast:
    - Recently concluded subsurface work across the Point Ligoure sub-licence asset has re-defined the subsurface structure resulting in a downward revision of 2C resources
    - Base Production Optimisation Operations to recategorize some 2C to 2P in particular execution of ABM151 RCP in Brighton

**Management's Estimate of Reserves and Resources as at 31 December 2021**

| Asset | 2021 2P Reserves mmstb | 2021 2C Reserves mmstb | 2021 2P and 2C Reserves mmstb | 2020 2P and 2C Reserves mmstb |
|---|---|---|---|---|
| Onshore | 7,26 | 3.82 | 11.08 | 9.45 |
| East Coast | 9.77 | 40.39 | 50.16 | 27.60 |
| West Coast | 2.7 | 3.01 | 5.71 | 5.75 |
| Total | 19.73 | 47.22 | 66.95 | 42.80 |

**Financial Review**

Strong financial performance underpinned by robust operational cashflows. The recovery in crude oil prices, combined with our continued financial discipline, meant we were able to generate solid results and invest in short to medium term growth initiatives.

**KPIs**

The Group's robust performance resulted in it being profitable at both an operating and total comprehensive income level in 2021, despite the backdrop of the ongoing Covid-19 pandemic.

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

| | | FY 2021 | FY 2020 | Change % |
|---|---|---|---|---|
| Average realised oil price[1] | USD/bbl | 60.4 | 37.7 | 60 |
| Average net sales[2] | bopd | 3,006 | 3,226 | (7) |
| Revenues | USD million | 66.2 | 44.1 | 50 |
| Cash balance | USD million | 18.3 | 20.2 | (9) |
| **IFRS Results** | | | | |
| Operating Profit before SPT & PT | USD million | 10.0 | 3.0 | 233 |
| Total Comprehensive income/(loss) for the year | USD million | 7.7 | (2.8) | 375 |
| Earnings Per Share – Diluted | USD cents | 18.0 | (7.0) | 357 |
| **APM Results** | | | | |
| Adjusted EBITDA[3] | USD million | 19.8 | 12.1 | 64 |
| Adjusted EBITDA[4] | USD/bbl | 18.0 | 10.3 | 75 |
| Adjusted EBITDA margin[5] | % | 29.9 | 27.4 | 2.5 |
| Adjusted EBITDA after Current Taxes[6] | USD million | 14.8 | 10.6 | 40 |
| Adjusted EBITDA after Current Taxes Per Share – Diluted | US cents | 35.0 | 25.0 | 39 |
| Consolidated operating break-even[7] | USD/bbl | 29.2 | 20.1 | 45 |
| Net cash plus working capital surplus[8] | USD million | 20.8 | 21.4 | (3) |

Notes:

1. Average realised price (USD/bbl): Actual price received for crude oil sales per barrel ("bbl").
2. Average net sales (bopd): Production sold in barrels per day in a given year.
3. Adjusted EBITDA (USD MM): Operating Profit before Taxes for the period, adjusted for non- cash DD&A, SOE, ILFA, FX gain/(loss) and Fair Value Gains/Losses on Derivative Financial Instruments less Covid-19 expenses.
4. Adjusted EBITDA (USD/bbl): Adjusted EBITDA/Annual sales.
5. Adjusted EBITDA margin (%): Adjusted EBITDA/Revenues.
6. Adjusted EBITDA after Current Taxes: Adjusted EBITDA less Supplemental Petroleum Taxes ("**SPT**"), Property Taxes ("**PT**"), Petroleum Profits Tax ("**PPT**") and Unemployment Levy ("**UL**").
7. Consolidated operating break-even: The realised price/bbl where the Adjusted EBITDA/bbl for the Group is equal to zero.
8. Net cash plus working capital surplus: Current Assets less Current Liabilities (other than Derivative financial asset / liability and Provision for other liabilities).

Note (*): See Note to Consolidated Financial Statements – Adjusted EBITDA for further details

**Adjusted EBITDA Calculation**

Adjusted EBITDA is an Alternative Performance Measure ("APM") 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 underlying operational and financial performance.

| | 2021<br>USD MM | 2020<br>USD MM | Change % |
|---|---|---|---|
| Operating Profit Before SPT, PT, Covid-19 expenses, Impairment and Exceptional Items (IFRS Result) | 10.0 | 3.0 | 238 |

| | | | |
|---|---|---|---|
| DD& A | 7.4 | 8.2 | (9) |
| SOE | 0.6 | 1.0 | (35) |
| ILFA | (0.7) | 0.2 | (399) |
| FX loss/(gain) | 0.0 | (0.0) | 0 |
| FV Derivative Instruments | 3.2 | (0.3) | 1,284 |
| Covid-19 expenses | (0.7) | - | 100 |
| **Adjusted EBITDA (APM Result)** | **19.8** | **12.1** | **64** |
| Current Taxes: | | | |
| SPT and PT | (3.6) | (0.4) | 839 |
| PPT and UL | (1.4) | (1.1) | 20 |
| **Adjusted EBITDA after Current Taxes (APM Result)** | **14.8** | **10.6** | **40** |

**2021 Trading Summary**

A five year historical summary of realised price, sales, operating break-even, Royalties, Production Costs ("Opex") and General & Administrative ("G&A") expenditure metrics is set out below.

| **Details** | | **2017[1]** | **2018[1]** | **2019** | **2020** | **2021** |
|---|---|---|---|---|---|---|
| Realised Price | USD/bbl | 48.6 | 59.8 | 58.1 | 37.7 | 60.4 |
| Sales | | | | | | |
| Onshore | bopd | 1,347 | 1,563 | 1,616 | 1,793 | 1,644 |
| West Coast | bopd | 212 | 198 | 185 | 245 | 255 |
| East Coast | bopd | 961 | 1,110 | 1,208 | 1,188 | 1,107 |
| Consolidated | bopd | 2,519 | 2,871 | 3,007 | 3,226 | 3,006 |
| | | | | | | |
| **Metrics** | | | | | | |
| Royalties/bbl – Onshore | USD/bbl | 18.5 | 24.2 | 22.3 | 11.5 | 22.6 |
| Royalties /bbl – West Coast | USD/bbl | 7.5 | 10.0 | 10.0 | 6.1 | 11.1 |
| Royalties /bbl – East Coast | USD/bbl | 11.7 | 14.5 | 14.1 | 8.3 | 13.0 |
| Royalties /bbl – Consolidated | USD/bbl | 22.2 | 19.1 | 18.3 | 9.9 | 18.1 |
| | | | | | | |
| Opex/bbl – Onshore | USD/bbl | 11.1 | 11.7 | 12.1 | 12.2 | 14.4 |
| Opex/bbl – West Coast | USD/bbl | 22.1 | 22.1 | 26.9 | 20.3 | 26.2 |
| Opex/bbl – East Coast | USD/bbl | 18.9 | 20.1 | 17.1 | 16.5 | 18.3 |
| | | | | | | |
| G&A/bbl – Consolidated[2] | USD/bbl | 4.4 | 5.0 | 5.1 | 4.3 | 6.3 |
| | | | | | | |
| **Operating Break-Even[3]** | | | | | | |
| | | **2017[4]** | **2018[4]** | **2019** | **2020** | **2021** |
| Onshore | USD/bbl | 16.6 | 16.1 | 16.4 | 16.5 | 19.0 |
| West Coast | USD/bbl | 26.6 | 26.8 | 32.4 | 24.6 | 32.2 |
| East Coast | USD/bbl | 24.9 | 25.9 | 21.9 | 21.0 | 23.2 |
| Consolidated[4] | USD/bbl | 28.4 | 29.0 | 26.4 | 20.1 | 29.2 |

Notes

1. Metrics for 2018 and prior are pre-IFRS 16 adoption effective 1 January 2019 which impacted the Operating Break-Even Levels and Opex/bbl & G&A/bbl Metrics for historical comparative purposes. Full details of the impact were set out in the 2019 annual report and accounts.
2. G&A/bbl – Consolidated: Excludes SOE, ILFA, Derivative FV gain/loss and FX gain/loss.
3. Operating break-even: The realised price where Adjusted EBITDA for the respective asset or the entire Group (Consolidated) is equal to zero.
4. Consolidated operating break-even: Includes G&A but excludes SOE, ILFA, Derivative FV gain/loss and FX gain/loss.

**Review of Financial Statements**

Trinity and its subsidiaries ("the Group") consolidated financial information has been prepared on a going concern basis, in accordance with international accounting standards as adopted in the United Kingdom. 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.

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".

In particular, the APM measure of Adjusted EBITDA excludes the impact of Depreciation, Depletion & Amortisation ("DD&A"), as well as the non-cash impact of Share Option Expense ("SOE"), Impairment losses on financial assets ("ILFA"), FX gain/loss and Fair Value Gains/Losses on Derivative Financial Instruments. Each of these are summarised on the face of the Consolidated Income Statement as well as being described in Note 1 to the consolidated financial statements.

**Summary of Results for the Year**

**Revenue increased due to the material higher average realised oil price in 2021:** The positive impact of a 60% increase in average oil price realisations to USD 60.4/bbl (2020: USD 37.7/bbl), was partially offset by a 7% decrease in average annual sales to 3,006 bopd (2020: 3,226 bopd), resulting in a 50% increase in revenues to USD 66.2 million (2020: USD 44.1 million).

**Continued financial discipline on costs and preserving strong operating margins:** The Group continued to deliver strong operating margins despite an increase in costs incurred in dealing with the pandemic. The Adjusted EBITDA margin increased to 30% (2020: 27%), with consolidated operating break-even maintained at below USD 30 (2021: USD 29.2/bbl, 2020: USD 20.1/bbl) demonstrating the Group's ability to be profitable across a broad range of oil prices. The 64% increase in Adjusted EBITDA to USD 19.8 million (2020: USD 12.1 million) is a direct result of the increased realised oil price and strong operational performance.

**Increased capex investment programme to drive growth in the short to medium term:**
USD 13.9 million (2020: USD 5.3 million) invested acquiring a new onshore lease operatorship (PS 4, onshore), acquiring 3D Seismic data covering Trinity's onshore acreage, exploration and evaluation spend on the Galeota Asset Development, continuing investment in the Group's Infrastructure, Subsurface, Drilling planning and execution of 11 RCPs.

Capex invested comprised:

- USD 3.8 million acquisition of PS-4 Lease Operatorship
- USD 3.2 million Exploration and Evaluation ("E&E") assets relating to the Galeota Asset Development
- USD 3.2 million Infrastructure Capex
- USD 1.1 million acquisition of 3D Seismic Data
- USD 1.1 million Subsurface time-writing costs
- USD 0.8 million 11 RCPs
- USD 0.4 million in computer software and research and development
- USD 0.2 million renewal of Galeota block licences
- USD 0.1 million Drilling planning (no New Wells drilled).

Refer to Notes to Financial Statements: Note on Property, Plant and Equipment – Additions (USD 10.3 million) and Note on Intangible Assets – E&E Additions (USD 3.6 million) inclusive of accruals.

**Continued financial strength:** The Group's cash balances at year end reduced marginally by 9% to USD 18.3 million (2019: USD 20.2 million), primarily reflecting a strong operating performance offset increased taxes and derivative expenses and a material increase in capital spending. In aggregate, despite these significant cash outflows, the Group's net cash plus working capital surplus stood at USD 20.8 million, a modest 3% decrease (2020: USD 21.4 million).

**Statement of Comprehensive Income**

**2021 Financial Highlights**

Average realisation of USD 60.4/bbl (2020: USD 37.7/bbl)

**Operating Revenues**
Operating revenues up 50% to USD 66.2 million (2020: USD 44.1 million).

**Operating expenses**
Operating expenses increased by 37% in 2021 to USD (56.2) million reflecting a return to a cost structure similar to that which prevailed in 2019 (2020: USD (41.1) million) and comprised:

**Operating Expenses (excluding non-cash items): USD (45.7) million (2020: (31.9) million):**

- Royalties of USD (19.9) million (2020: USD (11.7) million), this increase being driven mainly due to higher average realised oil price.
- Opex of USD (17.6) million (2020: USD (16.5) million) mainly due to a recovery in crude oil prices from lows in 2020 which had a commensurate impact on supply chain prices as well as increased workover and swabbing activity in the year.
- G&A expenses of USD (7.0) million (2020: USD (5.1) million) mainly due to an increase in new hires, employee bonuses, a one off director payment to the estate of Bruce Dingwall, an increase in professional services provided for the 2021 reserves audit and increased levies.
- Derivative expense of USD (1.2) million (2020: Derivative income of USD 1.3 million) being the cash impact of derivative instruments.

**Non-Cash Operating Expenses: USD (10.5) million (2020: USD (9.1) million):**

- DD&A of USD (7.4) million (2020: USD (8.2) million).
- Fair Value of Derivatives: Expense of USD (3.2) million (2020: Derivative income of USD 0.3 million) being the FV impact of derivative instruments
- SOE of USD (0.6) million (2020: USD (1.0) million).
- ILFA reversal/(charge) USD 0.7 million (2020: USD (0.3) million).

Operating Profit Before Supplemental Petroleum Taxes ("SPT") and Property Tax ("PT), Covid-19 expenses, Impairment and Exceptional Items

The operating profit before SPT, PT, Covid-19 expenses, impairment and exceptional items for the year amounted to USD 10.0 million (2020: USD 3.0 million) and was mainly due to higher operating revenues resulting from the higher oil prices.

**SPT & PT**
SPT & PT were net USD (3.6) million (2020: USD (0.4) million) and comprised:

- SPT of USD (5.1) million (2020: USD 0.2 million) mainly due to the higher realised oil prices in relation to the Group's offshore operations in 2021. There was no SPT payable in respect of the Group's onshore operations during the year.
- Reversal of PT charge of USD 1.5 million (2020: USD (0.5) million). The Property Tax Act and subsequent Amendment to the Act requires the Board of Inland Revenue to issue a Notice of Assessment on or before the 31 March in each year. As none have been received for the years 2018 to 2020, it is highly unlikely the tax will be required to be paid for these years and there is also no method to determine a reliable estimate for the liability. As such, the Company has made a reversal of the liability for periods 2018-2020 and not recognised any liability for 2021.

**Operating Profit before Covid expenses, Impairment and Exceptional items**
The Group's reported operating profit before Covid-19 expenses, impairment and exceptional items was USD 6.5 million (2020: USD 2.6 million). Adjusting for non-cash expenses, the Group's Adjusted EBITDA after Current Taxes was USD 14.8 million (2020: USD 10.6 million) (further details below).

**Covid-19 expenses**
Covid-19 expenses incurred by the Group for 2021 was USD (0.7) million. This was triggered when the Covid-19 impact to the country was at its highest and the Company sought to protect its workforce by early detection through Covid-19 testing USD (0.3) million, Offshore employee isolation prior to offshore rostering USD (0.3) million and heightened sanitisation efforts across the assets USD (0.1) million. Covid-19 expense of USD (0.1) million was previously recognised in 2020 in General and Administration expense relating to sanitation.

See Note 7 to Consolidated Financial Statements – Exceptional items and Covid-19 expenses for further details

**Impairments charge**
Impairment charges taken were USD (1.3) million (2020: USD (1.2) million) relating to the Impairment of property, plant, and equipment USD (0.1) million and Inventory (1.2) million.

See Note 3(d) to Consolidated Financial Statements - Impairment of Property, Plant and Equipment for further details

**Exceptional items**
Exceptional items were USD (0.1) million (2020: USD (0.04) million) mainly related to fees for corporate restructuring advice.

See Note 7 to Consolidated Financial Statements - Exceptional items and Covid-19 expenses for further details.

**Finance Income**
Finance income is solely related to bank interest income received on short term investments with financial institutions of USD 0.1 million (2020: 0.1 million).

**Finance Costs**
Finance costs amounted to USD (1.5) million (2020: USD (1.4) million) and comprised the:

- Unwinding of the decommissioning liability USD (1.2) million (2020: USD (1.2) million).
- Bank overdraft USD (0.2) million (2020: (0.1) million).
- Interest on Leases USD (0.1) million (2020: (0.1) million).

See Note 9 to Consolidated Financial Statements – Finance Costs for further details

**Income Taxation**
Income Taxation Credit for 2021 of USD 4.7 million (2020: USD (2.9) million expense), comprise the following:

- Increase in Deferred Tax Assets ("DTA") recognised on available tax losses of USD 5.5 million credit resulting from higher oil prices (2020: Reduction in DTA of USD 3.4 million expense).
- Decrease in Deferred Tax Liabilities ("DTL") USD 0.6 million due to accelerated accounting impairments/depreciation (2020: USD 1.6 million decrease).
- Unemployment Levy ("UL") USD (0.4) million (2020: USD (0.3) million).
- Petroleum Profit Tax ("PPT") charge USD (1.0) million (2020: (0.8) million).

See Note 10 to Consolidated Financial Statements – Income Taxation for further details

**Total Comprehensive Income/(Loss)**
Total Comprehensive Income for the period was USD 7.7 million (2020: USD (2.8) 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, Covid-19 expenses, Impairment and Exceptional Items for the year, adjusted for non-cash DD&A, SOE, ILFA, FX and FV of Derivative Instruments.

The Group presents Adjusted EBITDA at USD 19.8 million and Adjusted EBITDA after Current Taxes at USD 14.8 million as it is used by Management and judged to be a better measure of underlying performance.

**Statement of CashFlows**

**Cash inflow from operating activities**
Operating Cash Flow ("OCF") was USD 12.6 million (2020: USD 10.3 million):

- Operating activities 2021 generated an operating cash flow before working capital and income taxes of USD 16.1 million (2020: USD USD 11.9 million)

- Changes in working capital resulted in a net decrease of USD (1.8) million (2020: USD 0.6 million decrease), primarily as a result of the increase in trade receivables compared to the 2020 year end.
- Income taxes PPT and UL paid USD (1.7) million (2020: USD (1.0) million paid) resulting from higher oil price.

**Cash (outflow) from investing activities**
Cash outflow from investing activities was USD (13.9) million (2020: USD (6.0) million):

- Acquisition of PS 4, onshore 3D seismic, and property, plant and equipment for the year totalling USD (10.0) million (2020: USD (5.0) million)
- Expenditure on exploration and evaluation assets and other intangible assets USD (3.6) million (2020: USD (1.0) million) as the Group continued to invest in Galeota asset.
- Performance bond increase in renewal of Onshore Lease Operatorship Assets USD (0.3) million (2020: nil)

**Cash (outflow)/inflow from financing activities**
Cash outflow from financing activities was USD (0.6) million (2020: USD 2.2 million inflow):

- Principal paid on lease liability USD (0.4) million (2020: (0.4) million)
- Interest paid on lease liability USD (0.1) million (2020: (0.1) million)
- Finance cost of USD (0.1) million (2020: (0.0) million).
- No further drawdown on of CIBC working capital Facility (2020: USD 2.7 million drawdown).

**Closing Cash Balance**
Trinity's cash balance at 31 December 2021 was USD 18.3 million (31 December 2020: USD 20.2 million).

**Net Cash Plus Working Capital Surplus**

| | All figures in USD million | FY 2021 USD MM Audited | FY 2020 USD MM Audited | FY 2019 USD MM Audited |
|---|---|---|---|---|
| A: | **Current Assets** | | | |
| | Cash and cash equivalents | 18.3 | 20.2 | 13.8 |
| | Trade and other receivables | 10.8 | 7.2 | 9.4 |
| | Inventories | 3.8 | 5.3 | 5.2 |
| | Total Current Assets | 32.9 | 32.7 | 28.4 |
| B: | **Liabilities** | | | |
| | Trade and other payables | 8.8 | 7.8 | 10.4 |
| | Bank overdraft | 2.7 | 2.7 | — |
| | Lease liability | 0.6 | 0.6 | 0.6 |
| | Taxation payable | 0.0 | 0.2 | 0.1 |
| | Total Current Liabilities | 12.1 | 11.3 | 11.1 |
| (A-B): | **Net Cash plus working capital surplus** | **20.8** | **21.4** | **17.3** |

*Note: Net cash plus working capital surplus: Current Assets less Current Liabilities (other than Derivative financial asset/liability and Provision for other liabilities).*

**Reconciliation between Adjusted EBITDA after Current Taxes and Cash Inflow from Operating Activities**

| | |
|---|---|
| Adjusted EBITDA after Current Taxes | **14.8** |
| Changes in working capital | (1.9) |
| Add back current tax | 1.4 |
| Income taxation paid | (1.7) |
| Cash inflow from Operating Activities | **12.6** |

**Events since Year End**

1. **Hedging**

The Company implemented crude oil derivatives over the Group’s monthly production in 2021 and 2022.

The derivative protection currently in effect for 2022 is as follows:

| Type of Derivatives | Index | Sell Put USD/ bbl | Buy Put USD/ bbl | Sell Call USD/ bbl | Buy Call USD/ bbl | Production Monthly Barrels | Effective Date | Expiry Date | Execution Date | Premium USD MM |
|---|---|---|---|---|---|---|---|---|---|---|
| 3-Way Cost Collar | ICE Brent | 50.00 | 60.00 | 66.90 | - | 10,000 | 1-Jan-22 | 30-Jun-22 | 04-Mar-21 | |
| 3-Way Cost Collar | ICE Brent | 50.00 | 60.00 | 74.40 | - | 12,500 | 1-Jan-22 | 31-Dec-22 | 02-Jun-21 | |
| 4-Way Cost Collar | ICE Brent | 59.00 | 68.00 | 72.00 | 82.00 | 15,000 | 1-Jan-22 | 30-Jun-22 | 05-Jul-21 | |
| 3-Way Cost Collar | ICE Brent | 40.00 | 50.00 | 80.50 | - | 15,000 | 1-Jan-22 | 31-Dec-22 | 27-Aug-21 | |
| Put Spread Option | ICE Brent | 40.00 | 50.00 | - | - | 15,000 | 1-Jul-22 | 31-Dec-22 | 14-Jan-22 | 0.15 |

2. On 24 February 2022, Russian forces invaded Ukraine, causing wide-ranging economic sanctions to be applied against the Russian regime by the US, EU and other major economies. The event caused both Brent and WTI oil prices to soar, peaking well above USD 100 per bbl in March 2022. The increased oil prices has positively impacted the Group’s crude oil revenue but negatively impacted derivative expenses. Overall, whilst there has been no significant adverse impact to the Group, management continues to closely monitor the event’s impact as it unfolds.
3. In 2021 Trinity engaged with a range of potential partners as part of the Galeota farm down process. The Company on 3 May 2022 indicated, whilst initial feedback has been encouraging, a number of participants have informed the Company that they are unable to fully assess the economics of the opportunity at Galeota without clarity on the expected reforms to Supplemental Petroleum Tax (“SPT”), which are currently being considered by the Government of Trinidad and Tobago (“GORTT”) and which were initially expected to have been confirmed sooner than now appears likely. Pending SPT reform, which management still expects to happen, the Company has decided to pause the Galeota farm down process. This will enable the Company to seek the best value proposition for Galeota when the GORTT's fiscal reforms have been confirmed.

   In the interim, the Company will continue to refine its plans for Galeota. In particular, it will advance preparations for exploiting the 9.77mmbls of 2P reserves remaining in the Trintes field.

**Consolidated Statement of Comprehensive Income**
**For the year ended 31 December 2021**
(Expressed in United States Dollars)

| | Note | 2021 | 2020 |
|---|---|---|---|
| | | **$'000** | **$'000** |
| **Revenues** | | | |
| Crude oil sales | | 66,257 | 44,074 |
| Other income | | 1 | 4 |
| | | **66,258** | **44,078** |
| **Operating Expenses** | | | |
| Royalties | | (19,828) | (11,746) |
| Production costs | | (17,625) | (16,458) |
| Depreciation, Depletion & Amortisation ("DD&A") | 13-15 | (7,428) | (8,174) |
| General & Administrative ("G&A") expenses | | (7,030) | (5,095) |
| Net reversal/ (Impairment losses) on financial assets ("ILFA") | | 754 | (252) |
| Share Option Expense ("SOE") | | (626) | (963) |
| Foreign exchange ("FX") (loss)/gain | | (14) | 7 |
| Derivative (expense)/income (realised) | 6 | (1,293) | 1,302 |
| Fair value (expense)/income derivative instruments (unrealised) | 6 | (3,149) | 266 |
| | | **(56,239)** | **(41,113)** |
| **Operating Profit before Supplemental Petroleum Taxes ("SPT") & Property Taxes ("PT")** | | **10,019** | **2,965** |
| SPT | | (5,074) | 153 |
| PT net reversal/(charge) | | 1,516 | (532) |
| **Operating Profit before Covid expenses, Impairment and Exceptional items** | | **6,461** | **2,586** |
| Covid-19 expenses | 7 | (669) | -- |
| Impairment | 8 | (1,316) | (1,218) |
| Exceptional items | 7 | (113) | 43 |
| **Operating Profit** | | **4,363** | **1,411** |
| Finance income | 9 | 94 | 108 |
| Finance costs | 9 | (1,475) | (1,416) |
| **Profit Before Income Taxation** | | **2,982** | **103** |
| Income taxation credit/(charge) | 10 | 4,744 | (2,938) |
| **Profit/(Loss) for the year** | | **7,726** | **(2,835)** |
| **Other Comprehensive Income/(Expense)** | | | |
| **Items that may be subsequently reclassified to profit or loss** | | | |
| Currency translation | | -- | (1) |
| **Total Comprehensive Income/(Loss) for the year** | | **7,726** | **(2,836)** |

| | | | |
|---|---|---|---|
| **Earnings per share (expressed in dollars per share)** | | | |
| Basic* | 11 | 0.20 | (0.07) |
| Diluted* | 11 | 0.18 | (0.07) |

** See note 23 regarding restatements as a result of the share capital reorganisation.*

**Consolidated Statement of Financial Position**
**at 31 December 2021**
(Expressed in United States Dollars)

| | Note | 2021 | 2020 |
|---|---|---|---|
| **ASSETS** | | **$'000** | **$'000** |
| **Non-current Assets** | | | |
| Property, plant and equipment | 13 | 49,507 | 37,756 |
| Right-of-Use ("ROU") assets | 14 | 616 | 1,014 |
| Intangible assets | 15 | 30,759 | 27,349 |
| Abandonment fund | 16 | 4,021 | 3,490 |
| Performance bond | 17 | 473 | 253 |
| Deferred Tax Assets ("DTA") | 18 | 11,530 | 5,997 |
| | | 96,906 | 75,859 |
| **Current Assets** | | | |
| Inventories | 19 | 3,820 | 5,267 |
| Trade and other receivables | 20 | 10,747 | 7,239 |
| Derivative financial instruments | 21 | -- | 266 |
| Cash and cash equivalents | 22 | 18,312 | 20,237 |
| | | 32,879 | 33,009 |
| **Total Assets** | | **129,785** | **108,868** |
| **EQUITY AND LIABILITIES** | | | |
| **Capital and Reserves Attributable to Equity Holders** | | | |
| Share capital | 23 | 389 | 97,692 |
| Share premium | 23 | -- | 139,879 |
| Share based payment reserve | 24 | 3,784 | 14,764 |
| Merger reserves | 25 | -- | 75,467 |
| Reverse acquisition reserve | 25 | (89,268) | (89,268) |
| Translation reserve | | (1,650) | (1,650) |
| Retained earnings/ (accumulated losses) | | 143,666 | (188,332) |
| **Total Equity** | | **56,921** | **48,552** |
| **Non-current Liabilities** | | | |
| Lease liability | 14 | 97 | 465 |
| Deferred Tax Liabilities ("DTL") | 18 | 2,025 | 2,611 |
| Provision for other liabilities | 27 | 55,690 | 45,405 |
| | | 57,812 | 48,481 |
| **Current Liabilities** | | | |
| Trade and other payables | 28 | 8,814 | 7,803 |
| Bank overdraft | 29 | 2,700 | 2,700 |
| Lease liability | 14 | 609 | 614 |
| Provision for other liabilities | 27 | 46 | 516 |
| Derivative financial liabilities | 21 | 2,883 | -- |
| Taxation payable | 31 | -- | 202 |
| | | 15,052 | 11,835 |
| **Total Liabilities** | | **73,864** | **60,316** |
| **Total Equity and Liabilities** | | **129,785** | **108,868** |

**Company Statement of Financial Position**
**at 31 December 2021**
(Expressed in United States Dollars)

| | Note | 2021 | 2020 |
|---|---|---|---|
| **ASSETS** | | **$'000** | **$'000** |
| **Non-current Assets** | | | |
| Investment in subsidiaries | 12 | 60,347 | 60,021 |
| **Current Assets** | | | |
| Trade and other receivables | 20 | 200 | 424 |
| Intercompany | 20 | 3,372 | 4,318 |
| Derivative financial instruments | 21 | -- | 266 |
| Cash and cash equivalents | 22 | 3,108 | 4,317 |
| | | 6,680 | 9,325 |
| **Total Assets** | | **67,027** | **69,346** |
| **EQUITY AND LIABILITIES** | | | |
| **Capital and Reserves Attributable to Equity Holders** | | | |
| Share capital | 23 | 389 | 97,692 |
| Share premium | 23 | -- | 139,879 |
| Share based payment reserve | | 4,569 | 4,064 |
| Merger reserves | | 6,552 | 56,652 |
| Retained earnings/ (accumulated losses) | | 51,526 | (229,422) |
| **Total Equity** | | **63,036** | **68,865** |
| **Current Liabilities** | | | |
| Trade and other payables | 28 | 327 | 481 |
| Intercompany | 30 | 781 | -- |
| Derivative financial liabilities | 21 | 2,883 | -- |
| | | 3,991 | 481 |
| **Total Liabilities** | | **3,991** | **481** |
| **Total Equity and Liabilities** | | **67,027** | **69,346** |

**Consolidated Statement of Changes in Equity**
**for the year ended 31 December 2021**
(Expressed in United States Dollars)

| Year ended 31 December 2020 | Share Capital $'000 | Share Premium $'000 | Share Based Payment Reserve $'000 | Reverse Acquisition Reserve $'000 | Merger Reserves $'000 | Translation Reserve $'000 | Retained Earnings/ Accumulated Losses $'000 | Total Equity $'000 |
|---|---|---|---|---|---|---|---|---|
| At 1 January 2020 | 97,692 | 139,879 | 14,328 | (89,268) | 75,467 | (1,649) | (186,024) | 50,425 |
| LTIPs exercised (Note 23) | -- | -- | (527) | -- | -- | -- | 527 | -- |
| Share based payment expense (Note 24) | -- | -- | 963 | -- | -- | -- | -- | 963 |
| Translation difference | -- | -- | -- | -- | -- | (1) | -- | (1) |
| Loss for the year | -- | -- | -- | -- | -- | -- | (2,835) | (2,835) |
| **Total comprehensive loss for the year** | -- | -- | -- | -- | -- | (1) | (2,835) | (2,836) |
| **At 31 December 2020** | **97,692** | **139,879** | **14,764** | **(89,268)** | **75,467** | **(1,650)** | **(188,332)** | **48,552** |
| **Year ended 31 December 2021** | | | | | | | | |
| At 1 January 2021 | 97,692 | 139,879 | 14,764 | (89,268) | 75,467 | (1,650) | (188,332) | 48,552 |
| Capital reorganisation (Note 23 & 24) | (97,303) | (139,879) | (11,485) | -- | (75,467) | -- | 324,134 | -- |
| LTIPs exercised [1] | -- | -- | -- | -- | -- | -- | 47 | 47 |
| Share based payment expense (Note 24) | -- | -- | 505 | -- | -- | -- | 91 | 596 |
| Profit for the year | -- | -- | -- | -- | -- | -- | 7,726 | 7,726 |
| **Total comprehensive income for the year** | -- | -- | -- | -- | -- | -- | 7,726 | 7,726 |
| **At 31 December 2021** | **389** | **--** | **3,784** | **(89,268)** | **--** | **(1,650)** | **143,666** | **56,921** |

*[1] – As described in the notes to the consolidated financial statements, in 2020 the Company issued 4,745,057 ordinary shares (pre share consolidation) to certain employees on exercise of LTIPs at less than the nominal value in contravention of S580 of the Companies Act 2006. In 2021, on becoming aware of the issue, the Company sought remedial advice and corrected this.*

**Company Statement of Changes in Equity**
**for the year 31 December 2021**
(Expressed in United States Dollars)

| | Share Capital | Share Premium | Share Based Payment Reserve | Merger Reserves | Retained Earnings/ Accumulated Losses | Total Equity |
|---|---|---|---|---|---|---|
| | **$'000** | **$'000** | **$'000** | **$'000** | **$'000** | **$'000** |
| **Year ended 31 December 2020** | | | | | | |
| At 1 January 2020 | 97,692 | 139,879 | 3,628 | 56,652 | (229,833) | 68,018 |
| LTIPs exercised (Note 23) | -- | -- | (527) | -- | 527 | -- |
| Share based payment expense (Note 24) | -- | -- | 963 | -- | -- | 963 |
| Total comprehensive loss for the year | -- | -- | -- | -- | (116) | (116) |
| **At 31 December 2020** | **97,692** | **139,879** | **4,064** | **56,652** | **(229,422)** | **68,865** |
| **Year ended 31 December 2021** | | | | | | |
| At 1 January 2020 | 97,692 | 139,879 | 4,064 | 56,652 | (229,422) | 68,865 |
| Capital Reorganisation (Note 23 & 24) | (97,303) | (139,879) | -- | (50,100) | 287,282 | -- |
| Share based payment charge (Note 24) | -- | -- | 505 | -- | -- | 505 |
| LTIPs exercised[1] | -- | -- | -- | -- | 47 | 47 |
| Total comprehensive loss for the year | -- | -- | -- | -- | (6,381) | (6,381) |
| **At 31 December 2021** | **389** | **--** | **4,569** | **6,552** | **51,526** | **63,036** |

[1] – *As described in the notes to the consolidated financial statements, in 2020 the Company issued 4,745,057 ordinary shares (pre share consolidation) to certain employees on exercise of LTIPs at less than the nominal value in contravention of S580 of the Companies Act 2006. In 2021, on becoming aware of the issue, the Company sought remedial advice and corrected this.*

**Consolidated Statement of Cash Flows**
**for the year ended 31 December 2021**
(Expressed in United States Dollars)

| | Note | 2021<br>$'000 | 2020<br>$'000 |
|---|---|---|---|
| **Operating Activities** | | | |
| Profit before taxation | | 2,982 | 103 |
| Adjustments for: | | | |
| Translation difference | | (39) | 83 |
| Finance cost – loans and interest | 9 | 254 | 195 |
| Finance income | 9 | (94) | (108) |
| Finance cost – decommissioning provision | 27 | 1,222 | 1,221 |
| Share based payment charge | 24 | 626 | 963 |
| DD&A | 13-15 | 7,428 | 8,174 |
| Loss on disposal of assets | 13 | -- | 2 |
| Net reversal/ (Impairment loss) on financial assets | | (754) | 515 |
| Reversal of impairment | | -- | (126) |
| Inventory impairment | | 1,220 | -- |
| Impairment of property, plant and equipment | 13 | 96 | 1,121 |
| Fair value loss on derivative financial instruments | | 3,149 | (266) |
| Other non-cash items | | 47 | -- |
| | | **16,137** | **11,877** |
| **Changes In Working Capital** | | | |
| Inventories | 19 | 228 | (124) |
| Trade and other receivables | 16,20,21 | (3,019) | 1,556 |
| Trade and other payables | 21,27,28 | 909 | (1,985) |
| | | (1,882) | (553) |
| Income taxation paid | | (1,700) | (1,028) |
| **Net Cash Inflow from Operating Activities** | | **12,555** | **10,296** |
| **Investing Activities** | | | |
| Purchase of Exploration and Evaluation ("E&E") assets | 15 | (3,262) | (1,062) |
| Purchase of computer software and investment in research & development | 15 | (401) | -- |
| Purchase of property, plant and equipment | 13 | (9,957) | (4,979) |
| Performance bond released | | (220) | -- |
| **Net Cash Outflow from Investing Activities** | | **(13,840)** | **(6,041)** |
| **Financing Activities** | | | |
| Finance income | | 94 | 108 |
| Finance cost | | (153) | (55) |
| Principal paid on lease liability | | (480) | (441) |
| Interest paid on lease liability | | (101) | (140) |
| Bank overdraft | | -- | 2,700 |
| **Net Cash (Outflow)/Inflow from Financing Activities** | | **(640)** | **2,172** |
| **(Decrease)/Increase in Cash and Cash Equivalents** | | **(1,925)** | **6,427** |
| **Cash and Cash Equivalents** | | | |
| At beginning of year | | 20,237 | 13,810 |
| Effects of foreign exchange rates differences on cash | | 19 | (14) |
| (Decrease)/increase in Cash and Cash equivalents | | (1,944) | 6,441 |
| **At end of year** | 22 | **18,312** | **20,237** |

**Company Statement of Cash Flows**
**for the year ended 31 December 2021**
(Expressed in United States Dollars)

| | Note | 2021 $'000 | 2020 $'000 |
|---|---|---|---|
| **Operating Activities** | | | |
| Loss before taxation | | (6,381) | (116) |
| Adjustments for: | | | |
| Finance income | | (152) | (126) |
| Share based payment charge | | 178 | 248 |
| Net reversal of impairment loss on financial assets | | (28) | -- |
| Fair value loss on derivative financial instruments | | 3,149 | -- |
| Other non-cash items | | (13) | -- |
| | | **(3,247)** | **6** |
| **Changes In Working Capital** | | | |
| Trade and other receivables | | 1,537 | (1,074) |
| Trade and other payables | | 354 | (27) |
| | | **1,891** | **(1,101)** |
| **Taxation Paid** | | -- | -- |
| **Net Cash Outflow from Operating Activities** | | **(1,356)** | **(1,095)** |
| **Financing Activities** | | | |
| Finance income | | 147 | 126 |
| **Net Cash Inflow from Financing Activities** | | 147 | 126 |
| **Decrease In Cash and Cash Equivalents** | | **(1,209)** | **(969)** |
| **Cash and Cash Equivalents** | | | |
| At beginning of year | | 4,317 | 5,286 |
| Decrease Cash and Cash equivalents | | (1,209) | (969) |
| **At End of Year** | 22 | **3,108** | **4,317** |

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 Trinity Exploration & Production plc ("Trinity" or "the Company" or "Parent") and its subsidiaries (together "the Group").

**Background**

Trinity is an independent energy company limited by shares and listed on the Alternative Investment Market ("AIM") market 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"). The Group is involved in the exploration, development and production of oil reserves in T&T.

**Basis of preparation**

The Group's and Company's financial statements have been prepared and approved by the Board of Directors ("Board") in accordance with international accounting standards as adopted in the United Kingdom.

The preparation of the consolidated financial statements in compliance with IFRS requires the use of certain critical accounting estimates. It also requires the Board and Executive Management Team ("EMT") (together "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 $6.4 million (2020: $0.1 million loss) driven mainly by the derivative expenses incurred in 2021.

*Basis of measurement*

This consolidated financial statements has been prepared under the historical cost convention, except certain financial assets and liabilities (including derivative financial instruments) 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.

**Going Concern**

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

In making their going concern assessment, the Board have considered the Group's current financial position, budget and cash flow forecast for the next twelve months. For the past twelve months the Group continued to operate with no significant effects nor interruptions from the presence of the Covid-19 pandemic. However, the Board have continued to measure 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. The going concern assessment has considered the current operating environment and the potential impact of the volatility of the oil price. Oil prices have trended in an upward direction throughout 2021 and continued to increase in 2022 well over US$100 as at the date of this annual report. Oil prices are forecast to remain at elevated levels over the next 12 months, which will continue to positively impact the Group's operations.

The Group started 2022 with a strong operating and financial position; 2021 average sales of 3,006 barrels of oil per day ("bopd"), (2020 3,226 bopd), and net cash of US$15.6 million (2020: US$17.5 million) consisting of cash and short term investments of US$18.3 million (2020: US$20.2 million) and an overdraft facility of US$2.7 million drawn (2020: US$2.7 million) as at 31 December 2021. In making their going concern assessment, the Board considered a cash flow forecast based on expected future oil prices, production volumes and discretionary expenditure reductions including downside scenarios. The base case forecast was prepared with consideration of the following:

- Future oil prices assumed to be in line with the forward curve prevailing as at January 2022, with an average realised oil price of US$68.7/bbl in the period to December 2022. The forward price curve applied in the cash flow forecast starts at US$70.6/bbl in January 2022, fluctuating each month down to US$65.8/bbl in December 2022 through to US$63.4/bbl in June 2023
- Average forecast production for the year to December 2022 of 3,173 bopd and for the six months to June 2023 of 3,133 bopd with production being maintained by RCPs, WOs and swabbing activities and no new drilling;
- No SPT incurred on the onshore assets in 2022, as the SPT threshold for small onshore operators was increased from US$50 to US$75.0/bbl for 2022;
- Trinity continuing to progress various growth and business development opportunities; and derivative instruments in place to protect a portion of cashflows against declining oil prices over the forecast period.

As at the current date, Management considers this is a reasonable base scenario, reflecting the outlook of the current production profile and costs. As oil prices have trended upwards our base scenario will continue to be strengthened. The cash flow forecast showed that the Group will remain in a strong financial position for at least the next twelve months, and as such being able to meet its liabilities as they fall due.

Management has considered separate stressed scenarios including:

- the effect of reductions in oil prices as low as $40.0/bbl being sustained across the forecast period, noting that the base case pricing is in line with market prices; and

- the impact of temporary disruption from localised Covid-19 cases reducing forecast production by 10%, albeit operations have continued uninterrupted to date and the nature of the operations reduces the risk of such an eventuality.

All reasonably possible forecasts demonstrate that the Group's cash balances are maintained under such scenarios and being sufficient to meet the Group's obligations as they fall due.

Based on the cash flow forecast, when combined with mitigating actions that are within the Group's control and having considered the potential impact of Covid-19 pandemic, together with the Government of Trinidad and Tobago's ("GORTT's") response to date, the Board currently believe the Group can maintain sufficient liquidity and a healthy positive cash balance, and remain in operational existence, for at least the next twelve months.

On 24 February 2022, Russian forces invaded Ukraine, causing wide-ranging economic sanctions to be applied against the Russian regime by the US, EU and other major economies. The event caused both Brent and WTI oil prices to soar, peaking well above US$ 100 per bbl in March 2022. The increased oil prices have impacted the Group in several ways. These include, positively impacted the Group's crude oil revenue, negatively impacted derivative expenses, increased inflationary impacts and some challenges with supply chain including higher freight costs and delays in receiving shipments. Overall, whilst there has been no significant adverse impact to the Group, management continues to closely monitor the event's impact as it unfolds.

As a result, at the date of approval of the financial statements, the Board have a reasonable expectation that the Group has sufficient and adequate resources to continue in existence for at least twelve months post approval of these financial statements and is poised for continued growth as market conditions continue to 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 consolidated and company financial statements.

**Changes in accounting policies**

**(a) <u>New standards, interpretations and amendments adopted from 1 January 2021:</u>**

New standards impacting the Group that have been adopted in the annual financial statements for the year ended 31 December 2021 are:

- Covid-19-Related Rent Concessions beyond 30 June 2021 (Amendments to IFRS 16)

  On 31 March 2021, the IASB issued another amendment to IFRS 16: Covid-19-Related Rent Concessions beyond 30 June 2021, which extended the above practical expedient to reductions in lease payments that were originally due on or before 30 June 2022. This amendment is effective for annual periods beginning on or after 1 April 2021 with earlier application permitted.

- Interest Rate Benchmark Reform – IBOR 'phase 2' (Amendments to IFRS 9, IAS 39, IFRS 7, IFRS 4 and IFRS 16)

  The amendments provide relief to Group in respect of certain loans whose contractual terms are affected by interest benchmark reform.

The application of these standards has had no impact on the disclosures, or the amounts recognised in the Group's consolidated financial statements.

**(b) New standards, interpretations and amendments not yet effective**

There are a number of standards, amendments to standards, and interpretations which have been issued by the IASB that are effective in future accounting periods that the Group has decided not to adopt early.

The following amendments will become effective for the period beginning 1 January 2022 (and, in the case of IFRS 17, 1 January 2023):

- Property, Plant and Equipment: Proceeds before Intended Use (Amendments to IAS 16);
- Annual Improvements to IFRS Onerous Contracts – Cost of Fulfilling a Contract (Amendments to IAS 37);
- Standards 2018-2020 (Amendments to IFRS 1, IFRS 9, IFRS 16 and IAS 41);
- References to Conceptual Framework (Amendments to IFRS 3). Disclosure of Accounting Policies (Amendments to IAS 1 and IFRS Practice Statement 2);
- Definition of Accounting Estimates (Amendments to IAS 8);
- Deferred Tax Related to Assets and Liabilities arising from a Single Transaction (Amendments to IAS 12); and
- IFRS 17 Insurance Contracts (effective 1 January 2023) - In June 2020, the IASB issued amendments to IFRS 17, including a deferral of its effective date to 1 January 2023.

While no formal assessment has been performed, the Group does not expect any other standards issued by the IASB, but not yet effective, to have a material impact on the Group.

**Basis of consolidation**

The Consolidated Financial Statements comprise the financial statements of the subsidiaries listed in Note 12. The 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. 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.

*Employee Benefit Trust*
On 15 November 2021, the Group established The Trinity Exploration and Production plc Employee Benefit Trust, which is consolidated in accordance with the principles in Note 1 – Basis of consolidation. When the options are exercised, trust transfers the appropriate number of shares to the employee. The proceeds received, net of any directly attributable transaction costs, are credited directly 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 currencies of the Group operating entities are Trinidad & Tobago Dollars ("TTD") and USD as these are the currencies 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 consolidated 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:

| | **2021** | | **2020** | |
|---|---|---|---|---|
| | $ | £ | $ | £ |
| Average rate TTD= $/£ | 6.765 | 9.006 | 6.758 | 8.646 |
| Closing rate TTD= $/£ | 6.763 | 9.151 | 6.761 | 9.213 |

*(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 the consolidated Statement of Comprehensive Income. 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.

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 the consolidated Statement of Comprehensive Income as part of the fair value gain or loss and translation differences on non-monetary assets.

*(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 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. E&E assets are reclassified from E&E when evaluation procedures have been completed including technical feasibility and commercial viability. E&E assets for which commercially viable reserves have been identified are reclassified to development assets (refer to E&E expenditure below).

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&E assets' Fair Value Less Costs of Disposal ("FVLCD") 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.

Transactions involving the purchases of an individual field interest, or a group of field interests, that at a minimum includes an input and a substantive process that together significantly contribute to the ability to create output are classified as a business acquisition. The acquisition method of accounting is used to account for all business combinations. Alternatively, if these transactions do not meet this definition of a business combination they are classified as asset acquisitions. Assets are recognised at its fair value and subsequently depreciated over its useful life or reduced using the unit of production method.

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 capitalisation being 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 FVLCD 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 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 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 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 weighted 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.

**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**

The financial assets within the Group 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 cost and contract assets under IFRS 15: Revenue from Contracts with Customers. The measurement of ECL reflects an unbiased and probability weighted amount that is available without undue cost or effort at the reporting date, about past events, current conditions and forecasts of future economic conditions. The Group applied the simplified approach to determine impairment of its trade and other receivables. The simplified approach requires expected lifetime losses to be recognised from initial recognition of the receivables. This involves determining the expected loss rates using a provision matrix that is based on the Group's historical default rates observed over the expected life of the receivables and adjusted 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 three 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 DTL 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 DTA 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 DTL 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")**

PT had been recognised initially at fair value and subsequently measured at amortised cost using the effective interest method. Assessments were 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 rates applicable to the Group were industrial with building rates at 6% and industrial without building rates at 3%.

Where PT accrued for past years is considered unlikely to be charged and paid, the accrual is reversed in the current year. Refer to note 3 (f) for further details.

**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"), 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.

Revenue associated with the sale of crude oil is measured based on the consideration specified in contracts with customers.

Revenue is recognised when control is transferred from the Group to its customer and the Group has the present right to payment. The transfer of control of crude oil coincides with title passing to the customer and the customer taking physical possession. 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, 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.

**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**

All leases are accounted for by recognising a right-of-use asset and a lease liability except for:

- Leases of low value assets; and
- Leases with a duration of 12 months or less.

Lease liabilities were measured at the present value of the contractual payments due to the lessor over the lease term, with the discount rate determined by reference to the group's incremental borrowing rate. 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 Central Bank of Trinidad and Tobago.

Right of use assets were initially measured at the amount of the lease liability. Subsequent to initial measurement lease liabilities increase as a result of interest charged at a constant rate on the balance outstanding and are reduced for lease payments made. Right-of-use assets are amortised on a straight-line basis over the remaining term of the lease.

The lease term can be described as the non-cancellable period of the lease plus periods covered by an option to extend or an option to terminate if the lessee is reasonably certain to exercise the extension option or not exercise the termination option.

In 2021 the Group revised its estimates due to an addition of two new leased vehicles in December 2021. As a result, there was a revision to the carrying amount of the lease liability to reflect the payments to be made over the revised term, which was discounted using the same incremental rate. Equivalent adjustment is made to the carrying value of the right-of-use asset, with the revised carrying amount being amortised over the remaining (revised) lease term.

**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 Derivative Income/(Expenses)) are measured at fair value through profit and loss.

Financial assets at fair value through profit or loss are 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.

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

**Royalty expense**

Royalty expense is recognized on an accrual basis in accordance with the substance of the relevant agreement. There are two types of royalties incurred, government royalties and overriding royalties in accordance with the various agreements held and are calculated based on the percentage rate multiplied by the barrels of oil produced. Government royalties are paid to the Government of Trinidad and Tobago on a quarterly and monthly basis based on the terms of the various agreements.

## 2 Financial Risk Management

**Financial risk factors**

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

Management is responsible for Group Risk Management and for identifying and evaluating financial risks.

**(a) Market risk**

*(i) Foreign currency ("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.

Foreign currency sensitivity

The Group is mainly exposed to the currency fluctuations of the US dollar. The sensitivity analysis principally arises on FX gain/loss on translation of the USD denominated receivables. The following table details the Group's sensitivity to a 10% (2020: 10%) increase and decrease in the functional currency (TT Dollar) of the main operating subsidiary against the US Dollar with all other variables held constant. 10% (2020: 10%) is the sensitivity rate that best represents Management's assessment of the possible change in the foreign exchange rates affecting the Group. A positive number below indicates an increase in profit and equity when the US dollar weakens against the functional currency. For a strengthening of the US Dollar against the functional currency, there would be an equal and opposite impact on the profit and equity, and the balances below would be negative.

| | 2021<br>$'000 | 2020<br>$'000 |
|---|---|---|
| Profit/(loss) for the year and Equity | | |
| 10% strengthening of the US Dollar/ (2020: 10%) | (247) | (168) |
| 10% weakening of the US Dollar/ (2020: 10%) | 247 | 168 |

*(ii) Price risk*

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

Price risk sensitivity

The Group is a price taker and is mainly exposed to the risk relating to price fluctuations. The following table details the Group's sensitivity to a 20% (2020: 20%) increase and decrease in realised oil prices. 20% (2020 20%) is the sensitivity rate that best represents Management's assessment of the possible change in the oil prices that may affect the group. A positive number below indicates an increase in revenue, while there would be an equal and opposite impact on revenue if there is a decrease in prices by 20%.

| | **2021** | **2020** |
|---|---|---|
| | **$'000** | **$'000** |
| Revenue | | |
| 20% increase in price/ (2020: 20%) | 13,168 | 11,702 |
| 20% decrease in price/ (2020: 20%) | (13,168) | (11,702) |

The Group implemented hedge options during the financial year, the purpose of which is to offer protection in the event of oil prices declining significantly.

*(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 maintaining a balance between floating and fixed contract rates.

At 31 December 2021, there were no loan commitments to attract interest rates on foreign currency-denominated borrowings, (2020: nil). During 2021 there was a bank overdraft facility which incurred $0.1 million interest (2020: $0.1 million).

(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, experience and the institution's credit rating to minimise risk. Our financial institutions credit rating in Trinidad and the UK are BBB- and A+ respectively (Standards and Poor 2021).

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

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 with the Petrotrin outstanding ORR incentive receipts. The ECL for those sales were assessed at the end of the year and was immaterial. A provision matrix was applied to determine the historical and forward-looking loss rates which was used to ultimately calculate an ECL allowance, which resulted in a provision being made of $0.01 million.

For the Heritage sales, the ECL was immaterial as all sales payments were made during the stipulated time frame. However, ECL was also calculated on Joint interest billings outstanding, which resulted in a provision of $0.1 million (2020: $0.9 million). Consequently, there was a net reversal of $0.8 million in the current period to reflect the decrease in the impairment provision. Similar to sales, a provision matrix was applied to determine the historical and forward-looking loss rates which was used to ultimately calculate an ECL allowance.

The Company also assessed impairment through the three-stage approach to derive at the ECL. Through assessing impairment via this method, a provision amount of $0.1 million (2020: $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 $18.3 million (2020: $20.2 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 following table sets out the contractual maturities (representing undiscounted contractual cash-flows) of financial liabilities.

| Group<br>**At 31 December 2021** | **Less than 1 year** | **1 to 2 years** | **2 to 5 years** | **Total** |
|---|---|---|---|---|
| | $'000 | $'000 | $'000 | $'000 |
| **Non-derivatives** | | | | |
| Trade and other payables | 8,814 | -- | -- | 8,814 |
| Bank overdraft | 2,700 | -- | -- | 2,700 |
| Lease liabilities | 609 | 50 | 47 | 706 |
| | 12,123 | 50 | 47 | 12,220 |
| **At 31 December 2020** | $'000 | $'000 | $'000 | $'000 |
| **Non-derivatives** | | | | |
| Trade and other payables | 7,803 | -- | -- | 7,803 |
| Bank overdraft | 2,700 | -- | -- | 2,700 |
| Lease liabilities | 614 | 442 | 23 | 1,079 |
| | 11,117 | 442 | 23 | 11,582 |

| Company<br>**At 31 December 2021** | **Less than 1 year** | **Total** |
|---|---|---|
| | $'000 | $'000 |
| **Non-derivatives** | | |
| Trade and other payables | 327 | 327 |
| Intercompany | 781 | 781 |
| | 1,108 | 1,108 |
| **At 31 December 2020** | $'000 | $'000 |
| **Non-derivatives** | | |
| Trade and other payables | 481 | 481 |
| | 481 | 481 |

(d) **Capital risk**

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 Cash/(Debt) divided by Total Capital. Net Cash/(Debt) is calculated as total borrowings less Cash and Cash equivalents. Borrowing relates to the overdraft facility where all covenants (current ratio not less than 1.25:1) were met. Total capital is calculated as 'equity' as shown in the Consolidated Statement Of Financial position plus Net Debt/(Net Cash).

| | 2021<br>$'000 | 2020<br>$'000 |
|---|---|---|
| Net cash | (15,612) | (17,537) |
| Total equity | 56,921 | 48,552 |
| Total capital | 41,309 | 31,015 |
| | | |
| Gearing ratio | (37.8)% | (56.5)% |

(e) **Fair value estimation**

The Group and Company have classified 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. See Note 21 for details.

**3. Critical Accounting Estimates and Judgements**

The preparation of the consolidated 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 to be made by Management which are based on key estimates of future cost, production volumes and price and are 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 during the period in which the change occurs. The Group has concluded that the DTA recognised will be recoverable within three years using approved business plans and budgets for the specific subsidiaries in which the DTA arose. See note 18.

(b) **Provision for decommissioning costs**

This provision is significantly affected by changes in technology, laws and regulations which may affect the actual cost and timing 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 and a core inflation rate. See Note 27: Provision for other liabilities

| | Bands (years) | 2021 | 2020 |
|---|---|---|---|
| Risk free rates | 8-12 | 1.80% | 3.14% |
| | 13-18 | 1.96% | 3.17% |

| | | | |
|---|---|---|---|
| | 19-25 | 2.20% | 2.42% |
| Inflation rate | | 2.40% | 2.00% |

The following table details the Group's sensitivity to a 1% (2020: 1%) increase and decrease in discount and inflation rates. 1% (2020: 1%) is the sensitivity rate that best represents Management's assessment of the possible change in the rates that may affect the Group. A positive number below indicates an increase in provisions and finance costs, while a negative number indicates a decrease in provisions and finance costs. The impact in 2021 of a 1% change in these variables is as follows:

| | **Consolidated Statement of Financial Position: Obligation 2021 $'000** | **Consolidated Statement of Comprehensive: Income/Expense 2021 $'000** |
|---|---|---|
| Discount rate | | |
| 1% increase in assumed rate | (8,917) | 262 |
| 1% decrease in assumed rate | 10,963 | (412) |
| Inflation rate | | |
| 1% increase in assumed rate | 10,813 | 225 |
| 1% decrease in assumed rate | (8,973) | (186) |

(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 2021 the Group estimated its own commercial reserves, guided by international Petroleum Resource Management System (PRMS) application guidelines, based on technical 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.

The key assumptions used in the estimation of reserves are as follows:

- Technical production profiles for the various assets onshore and offshore held by the Group.
- Economic assumptions such as forecast period, discount rate, crude price, operating cost, capital expenditure and fiscal structure.

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 and plant and equipment, may be affected due to changes in estimated future cash flows. See notes 13 and 15.
- Depreciation and amortisation charges in the Statement of Comprehensive Income are applied on a unit of production basis at a rate calculated by reference to proved and probable ("2P") reserve estimates and incorporating the estimated future cost of developing and extracting those reserves. There may be changes where such charges are determined using the unit of production method, or where the useful life of the related assets change. See notes 13 and 15.
- 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. See note 27.
- 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. See note 18.

As at 31 December 2021 all subsidiaries onshore and offshore 2P reserve estimates were re-evaluated by the EMT 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 FVLCD and VIU 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 2021 an impairment charge of $0.1 million was recognised on the Group's property, plant and equipment (2020: $1.1 million) see Note 13. The impairment charge resulted in the carrying amount of the respective CGUs being written down to their recoverable amount.

**Oil & Gas Assets $0.1 million (2020: $1.1 million) impairment**

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 9-24 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 2019 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. For the discounted cash flows to be calculated, Management has used a production profile based on its 2P reserve estimate of the assets and a range of assumptions *(see note 3(c)).* 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.

| | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|
| Realised price | 65.0 | 61.0 | 58.6 | 57.0 | 56.1 | 55.5 |

If the price deck used in the impairment calculation had been 10% lower than Management's estimates at 31 December 2021, the Group would have a $0.6 million increase on impairment of Oil & Gas Assets (2020: $1.0 million increase). If the price deck used in the impairment calculation had been 10% higher than Management's estimates at 31 December 2021, the Group would have a $0.1 million decrease on impairment of the Oil & Gas Assets (2020: $0.6 million decrease). 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 2021, Management's estimate of the Group's cost of capital was 13% (2020:12%). If the estimated cost of capital used in determining the post-tax discount rate for the CGU's had been 1% lower than Management's estimates the Group would have no change to the impairment position for 2021 (2020: $0.2 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 no change to the impairment position for 2021 (2020: $0.2 million increase).

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

In estimating the recoverability of exploration assets, Management considers contingent resources associated with certain evaluation assets as estimated by the Group's internal experts. Furthermore, Management factors in future development plans and licence expiries into the assessment. Exploration assets remain capitalised as long as sufficient progress is being made in assessing whether petroleum production is technically feasible and commercially viable. This assessment requires significant Management judgement, as exploration assets are subject to regular internal review to confirm the continued intent to establish the technical feasibility and commercial viability of a project. At the end of 2021 a review for impairment triggers was carried out and there were no 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.

(f) **Property tax reversal of prior period liability**

PT is assessed on property owned by the Group in Trinidad and Tobago governed by the Property Tax Act 2009 and later Property Tax 2018 amendment of Trinidad and Tobago. The calculation of PT is described in note 1 Background and Summary of significant accounting policies.

At the end of 2020 PT accrued for the period 2018 to 2020 within Trade and Other Payables was $1.5 million (2020: $1.0 million). PT has been accrued using the guidance provided by the legislation noted above, as the administration arrangements of the PT under the valuation of land act is not in place and the actual method for calculating PT is therefore unavailable.

The Property Tax Act and subsequent Amendment to the Act requires the Board of Inland Revenue to issue a Notice of Assessment on or before 31 March in each year. To date, none has been issued for any of the years 2018 to 2020 (nor for 2021). Based on public pronouncements the intention was to complete the assessment for residential properties by 2021 after which other categories can be assessed. Given the passage of time, it is remote that retroactive application will be implemented despite waivers being issued by the government for periods 2010-2017 but not for the period 2018-2021. Whilst there remains some ambiguity within the interpretation of the law, Industry practice within Trinidad means that it is appropriate to reverse the accrual.

The Group has considered whether a contingent liability exists, however given the judgement is that the law does not allow for retroactive application there is no liability arising from a past event. A liability will arise when the valuation roll has been completed and the Notice of Assessment given. The Group will continue to monitor developments in the Property tax law and reassess this at each reporting period.

As such, the Group has agreed reverse the PT accruals previously recognized ($1.5 million) for 2018 to 2020 and not recognize any PT liability for the year ended 31 December 2021.

(g) **PS-4 Asset Acquisition**

The Group completed the acquisition of the Block on 1 December 2021. IFRS 3 Business Combination, requires an assessment to be performed to determine whether the acquisition should be accounted for as a business combination or asset acquisition. To be considered a business acquisition, an acquired set must include an input and a substantive process that together significantly contribute to the creation of an output otherwise the acquisition is considered an asset acquisition. An assessment was performed and concluded that although the acquisition contains outputs, the vast majority of its value resides in the proved undeveloped reserves which does not contain any material input or output. As such, it was concluded the acquisition did not meet the requirements to be classified as a business combination and as such the acquisition was treated as an asset acquisition.

(h) **Share based payments**

The Company has in place a share-based compensation plan (the LTIP) for Executive Directors and the EMT which is designed to provide long term incentives to align interests with shareholders. The Company measures the cost of these equity-settled transactions by reference to the fair value of the equity instruments at the date at which they are granted. The fair value of share-based payments is measured using a Monte Carlo or Black-Scholes option pricing model. The measurement inputs to this model, including expected volatility, weighted average expected life of the instruments, expected dividends and risk-free interest rate, rely on Management judgements. See note 24 for details.

## 4 Segment Information

Management has determined the operating segments which are Onshore, West Coast and East Coast which are 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 EMT (which now comprises the Chief Executive Officer, Finance Director, Chief Operations Officer and Chief of Staff & General Counsel), which makes strategic decisions in accordance with Board policy.

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. All non-current assets of the Group are located in T&T.

## 5 Operating Profit Before Impairment, Covid-19 expenses and Exceptional Items

| | 2021<br>$'000 | 2020<br>$'000 |
|---|---|---|
| **Operating profit before impairment, Covid-19 expenses and exceptional items is stated after taking the following items into account:** | | |
| DD&A (Note 13) | 6,756 | 7,566 |
| Depreciation on ROU (Note 14) | 505 | 502 |
| Amortisation of computer software (Note 15) | 166 | 106 |
| Employee costs (Note 34) | 9,707 | 7,587 |
| Inventory recognised as expense, charged to operating expenses | 322 | 330 |

**Auditors' remuneration**

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

| | 2021<br>$'000 | 2020<br>$'000 |
|---|---|---|
| - Fees payable to the Company's auditors' and their affiliated firms for the audit of the parent Company and consolidated financial statements: | | |
| BDO LLP (UK based) | 161 | 136 |
| BDO Limited (T&T and Barbados based) | 84 | 84 |
| - Fees payable to the Company's auditors' for other services: | | |
| The audit of Company's subsidiaries | 16 | 13 |
| Audit related assurance services – interim review | 32 | 29 |
| **Total assurance and auditors' remuneration** | **293** | **262** |

| | 2021<br>$'000 | 2020<br>$'000 |
|---|---|---|
| **Professional services:** | | |
| Tax advice | 1 | -- |

All fees in 2021 are in respect of services provided by BDO 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. The professional fees relates to tax services rendered for advice on tax losses.

## 6 Derivative (expenses)/income

The net (loss)/ gain in fair value is recognised in the Consolidated Statement of Comprehensive Income during the year:

| | 31 December<br>2021<br>$'000 | 31 December<br>2020<br>$'000 |
|---|---|---|

| | | |
|---|---|---|
| Net derivative (expense)/income (realised) | (1,293) | 1,302 |
| FV of derivative financial instruments (unrealised) | (3,149) | 266 |
| | **(4,442)** | **1,568** |

## 7 Exceptional Items and Covid-19 expenses

**Exceptional items:**

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

| | 2021 $'000 | 2020 $'000 |
|---|---|---|
| Reversal of Impairment on equipment | -- | (126) |
| Fees relating to corporate restructuring advice | 113 | 83 |
| **Exceptional Expense/(Income)** | **113** | **(43)** |

***Exceptional items 2021:***

- Fees relating to corporate restructuring advice: 0.1 million charge in relation to professional advice on the capital reorganisation

| **Covid-19 expenses:** | **2021 $'000** | **2020 $'000** |
|---|---|---|
| Covid-19 expense | 669 | -- |
| | **669** | **--** |

- Covid-19 expense: $0.7 million charge in relation to Covid-19 costs incurred by the Group during 2021. Covid-19 expense of $0.1 million was previously recognised in General and Administration expense in the 2020 comparative.

## 8 Impairment

| | 31 December 2021 $'000 | 31 December 2020 $'000 |
|---|---|---|
| Impairment of Inventory | 1,220 | -- |
| Impairment of property, plant and equipment | 96 | 1,218 |
| Impairment expense | 1,316 | 1,218 |

- Impairment of inventory – $1.2 million charge in relation to inventory impairment. During the year Management engaged certified persons to conduct a review of high value slow moving inventory items which resulted in the above impairment. In 2020 there was no impairment on inventory items.

- Impairment of property, plant and equipment - $0.1 million charge in relation to property, plant and equipment. In 2020 and 2021 the impairment of property, plant and equipment related to charges for impairment losses on cash generating units (refer to Note 3(d)).

## 9 Finance income and costs

Recognised in the Consolidated Statement of Comprehensive Income

**Finance income**

| | 2021 $'000 | 2020 $'000 |
|---|---|---|
| Interest Income | 94 | 108 |

| **Finance costs** | **2021 $'000** | **2020 $'000** |
|---|---|---|
| Decommissioning – Unwinding of discount (Note 27) | (1,222) | (1,221) |
| Interest on Leases (Note 14) | (101) | (140) |
| Interest and other expenses on overdraft | (152) | (55) |
| | **(1,475)** | **(1,416)** |

## 10 Income Taxation

| | **2021 $'000** | **2020 $'000** |
|---|---|---|
| **Current tax** | | |
| Petroleum profits tax | 982 | 817 |
| Unemployment levy | 393 | 333 |
| | | |
| **Deferred Tax** | | |
| Current year | | |
| Movement in asset due to tax losses (recognised)/derecognised (Note 18) | (5,533) | 3,365 |
| Movement in liability due to accelerated tax depreciation (Note 18) | (586) | (1,577) |
| **Income tax (credit)/ expense** | **(4,744)** | **2,938** |

The Group's effective tax rate varies from the statutory rate for UK companies of 19% (2020:19%) as a result of the differences shown below:

| | **2021 $'000** | **2020 $'000** |
|---|---|---|
| **Profit before taxation** | **2,982** | **103** |
| Tax calculated at domestic tax rates applicable to profits in the respective countries | 3,441 | 741 |
| Expenses not deductible for tax purposes | 9,037 | 2,163 |
| Impact on tax losses | (2,595) | (2,187) |
| Deferred tax on capital allowances in the current period recognised | (9,087) | (1,389) |
| Tax losses previously generated now recognised in the current period | (5,533) | 3,365 |
| Other reconciling differences | (7) | 245 |
| **Tax (credit)/ charge** | **(4,744)** | **(2,938)** |

Corporate income tax is calculated at 19% (2020: 19%) of the assessable profit for the year for the UK parent company, 55% for the operating subsidiaries in Trinidad and Tobago (2020: 55%) and 30% (2020: 30%) for the corporate subsidiaries in Trinidad and Tobago.

Taxation losses at 31 December 2021 available for set off against future taxable profits amounts to approximately $234.6 million (2020: $237.2 million), with tax losses generated of $7.4 million (2020: $1.7 million) and tax losses utilised of $10.0 million (2020: $5.2 million) during the year. These losses do not have an expiry date and have not yet been confirmed by the Board of Inland Revenue ("BIR") and the Her Majesty's Revenue and Customs ("HMRC"). Tax losses carried forward by companies engaged in the petroleum production business in Trinidad and Tobago are restricted to set off in a year of income 75% of the otherwise chargeable profits.

## 11 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.

| | Profit/(loss) $'000 | Weighted Average Number Of Shares '000' | Earnings Per Share $ |
|---|---|---|---|
| **Year ended 31 December 2021** | | | |
| Basic | 7,726 | 38,879 | 0.20 |
| Diluted | 7,726 | 42,260 | 0.18 |
| **Year ended 31 December 2020** | | | |
| Basic* | (2,835) | 38,623 | (0.07) |
| Diluted* | (2,835) | 38,623 | (0.07) |

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 (see movements in number of LTIPs note 24) 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.

**Restatement*

*Comparative figures have been recalculated to conform with changes in presentation in the current year. The comparative figures were recalculated to show the impact on EPS resulting from the share consolidation which reduced the number of ordinary shares from 388,794,303 to 38,879,430 (refer to note 23). The impact of the restatement is summarised below:*

| | Profit/(Loss) $'000 | Weighted Average Number Of Shares '000 | Earnings Per Share $ |
|---|---|---|---|
| **Year ended 31 December 2020** | | | |
| Basic (restated) | (2,835) | 38,623 | (0.07) |
| Diluted (restated) | (2,835) | 38,623 | (0.07) |
| Basic | (2,835) | 386,233 | (0.01) |
| Diluted | (2,835) | 386,233 | (0.01) |

## 12 Investment In Subsidiaries

| | Company 2021 $'000 | Company 2020 $'000 |
|---|---|---|
| Opening balance | 60,021 | 59,306 |
| Share based payment reserve revision | (121) | -- |
| Share based payment | 447 | 715 |
| Closing balance | **60,347** | **60,021** |

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. In addition there was a revision to the Share based payment reserves as it relates to employees that no longer work for the Group.

**Listing of Subsidiaries**

The Group's subsidiaries at 31 December 2021 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 % |
| Trinity Exploration and Production (Galeota) Limited | Trinidad address | Oil and Gas | 100 % |
| Oilbelt Services Limited | Trinidad address | Oil and Gas | 100 % |
| Trinity Exploration and Production Services Limited | Trinidad address | Service Company | 100 % |
| Trinity Midstream Limited | Trinidad address | Oil and Gas | 100 % |
| Trinity Exploration and Production (Erin 1) Limited | Trinidad address | Oil and Gas | 100 % |
| Trinity Exploration and Production (Erin 2) Limited | Trinidad address | Oil and Gas | 100 % |
| Trinity Exploration and Production (Forest 1) Limited | Trinidad address | Oil and Gas | 100 % |
| Trinity Exploration and Production (Forest 2) Limited | Trinidad address | Oil and Gas | 100 % |
| Trinity Exploration and Production (Forest 3) Limited | Trinidad address | Oil and Gas | 100 % |
| Trinity Renewable Resources Limited | Trinidad address | Oil and Gas | 100 % |
| Trinity Exploration and Production plc Employee Benefit Trust | c/o Pinsent Masons LLP, 1 Park Row, Leeds, LS1 5AB, UK | Employee Benefit Trust | 100 % |

## 13 Property, Plant and Equipment

| Year ended 31 December 2021 | Plant & Equipment $'000 | Leasehold & Buildings $'000 | Oil & Gas Assets $'000 | Other $'000 | Total $'000 |
|---|---|---|---|---|---|
| Opening net book amount at 1 January 2021 | 2,028 | 1,481 | 34,247 | -- | 37,756 |
| Additions | 1,328 | 74 | 8,794 | -- | 10,196 |
| Adjustment to decommissioning estimate (Note 27) | -- | -- | 8,407 | -- | 8,407 |
| Impairment charge1 | -- | -- | (96) | -- | (96) |
| DD&A charge for year | (437) | (167) | (6,153) | -- | (6,757) |

| | Plant & Equipment $'000 | Leasehold & Buildings $'000 | Oil & Gas Assets $'000 | Other $'000 | Total $'000 |
|---|---|---|---|---|---|
| Translation differences | -- | -- | 1 | -- | 1 |
| **Closing net book amount at 31 December 2021** | **2,919** | **1,388** | **45,200** | **--** | **49,507** |
| At 31 December 2021 | | | | | |
| Cost | 16,222 | 3,412 | 318,058 | 336 | 338,028 |
| Accumulated DD&A and impairment | (13,303) | (2,024) | (272,858) | (336) | (288,521) |
| **Closing net book amount** | **2,919** | **1,388** | **45,200** | **--** | **49,507** |

| **Year ended 31 December 2020** | **Plant & Equipment $'000** | **Leasehold & Buildings $'000** | **Oil & Gas Assets $'000** | **Other $'000** | **Total $'000** |
|---|---|---|---|---|---|
| Opening net book amount at 1 January 2020 | 1,141 | 1,652 | 39,587 | -- | 42,380 |
| Disposals | -- | (2) | -- | -- | (2) |
| Additions | 1,124 | (16) | 2,983 | -- | 4,091 |
| Adjustment to decommissioning estimate (Note 27) | -- | -- | (152) | -- | (152) |
| Impairment reversal equipment | 126 | -- | -- | -- | 126 |
| Impairment charge[1] | (116) | -- | (1,005) | -- | (1,121) |
| DD&A charge for year | (247) | (153) | (7,166) | -- | (7,566) |
| **Closing net book amount at 31 December 2020** | **2,028** | **1,481** | **34,247** | **--** | **37,756** |
| At 31 December 2020 | | | | | |
| Cost | 14,894 | 3,338 | 300,857 | 336 | 319,425 |
| Accumulated DD&A and impairment | (12,866) | (1,857) | (266,610) | (336) | (281,669) |
| **Closing net book amount** | **2,028** | **1,481** | **34,247** | **--** | **37,756** |

1 *An impairment loss of $0.1 million (2020: $1.1 million) was recognised on Oil & Gas Assets (see Note 3 (d)) 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.*

## 14 Leases

The Group has recognised ROU assets and lease liabilities.

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

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

| | **31 December 2021** $'000 | **31 December 2020** $'000 |
|---|---|---|
| **Right-of-use assets** | | |
| Non-current assets | 616 | 1,014 |
| **Lease Liabilities** | | |
| Current | 609 | 614 |
| Non-current | 97 | 465 |
| | **706** | **1,079** |

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

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

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

| | 2021 $'000 | 2020 $'000 |
|---|---|---|
| **Depreciation charge of ROU assets** | | |
| Included in DD&A – ROU Depreciation | (505) | (502) |
| Interest expense (including finance cost) | (101) | (140) |

The total cash outflow for leases in 2021 was $0.6 million (2020: $0.6 million)

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

The Group leases various offices, equipment, staff housing and vehicles. Rental contracts are typically made for fixed periods of 6 months to 4 years.

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.

## 15 Intangible Assets

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

| **Year ended 31 December 2021** | **Exploration and Evaluation assets $'000** | **Computer software $'000** | **Research and Development $'000** | **Total $'000** |
|---|---|---|---|---|
| Opening net book amount at 1 January 2021 | 27,042 | 307 | -- | 27,349 |
| Additions | 3,175 | 355 | 46 | 3,576 |
| Amortisation charge for year | -- | (166) | -- | (166) |
| **Closing net book amount at 31 December 2021** | **30,217** | **496** | **46** | **30,759** |
| At 31 December 2021 | | | | |
| Cost | 30,217 | 877 | 46 | 31,140 |
| Accumulated amortisation | -- | (381) | -- | (381) |
| **Closing net book amount** | **30,217** | **496** | **46** | **30,759** |

| | **Exploration and Evaluation assets** | **Computer software** | **Research and Development** | **Total** |
|---|---|---|---|---|

| Year ended 31 December 2020 | $'000 | $'000 | $'000 | $'000 |
|---|---|---|---|---|
| Opening net book amount at 1 January 2020 | 25,987 | 268 | -- | 26,255 |
| Additions | 1,055 | 145 | -- | 1,200 |
| Amortisation charge for year | -- | (106) | -- | (106) |
| **Closing net book amount at 31 December 2020** | **27,042** | **307** | **--** | **27,349** |
| At 31 December 2020 | | | | |
| Cost | 27,042 | 520 | -- | 27,562 |
| Accumulated amortisation | -- | (213) | -- | (213) |
| **Closing net book amount** | **27,042** | **307** | **--** | **27,349** |

- E&E assets: Represents the cost of the TGAL 1 exploration well and further Galeota E&E costs. The Group tests whether E&E assets have suffered any impairment triggers on an annual basis and there were no impairment triggers identified in 2021 (2020: nil).

  In November 2021, the Group received approval for the Field Development Plan (FDP) for the Galeota Asset Development (GAD) from the MEEI. This approval confirmed the technical feasibility of the asset. To date, the Group is in the process of determining a funding plan to achieve commercial viability. As such, the Galeota E&E asset continues to be classified as an E&E asset until both the technical feasibility and commercial viability requirements are met.

- Computer Software: In 2021, costs incurred in connection with the acquisition of software.

- Research and Development: In 2021, costs incurred in connection with various initiatives reducing carbon emissions.

## 16 Abandonment fund

| | 2021 | 2020 |
|---|---|---|
| | **$'000** | **$'000** |
| At 1 January | 3,490 | 3,378 |
| Additions | 531 | 112 |
| At 31 December | **4,021** | **3,490** |

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.

## 17 Performance bond

| | 2021 | 2020 |
|---|---|---|
| | **$'000** | **$'000** |
| At 1 January and 31 December | 473 | 253 |

In June 2021 the Group's Lease Operatorship Assets ("LOA") licences were renewed with Heritage for ten years effective 1 January 2021 with the exception of the Fyzabad (FZ-2) licence which was extended for two years effective 1 January 2021. New Performance Bonds for each of the LOA were put in place totalling $0.47 million at a bond fee of 1.75% executed with First Citizens Bank Trinidad and Tobago Limited and effective until 31 December 2030. These funds have been restricted to fixed deposits for the period of the respective LOA licences at varying rates of interest.

## 18 Deferred Income Taxation

### Group

The analysis of DTA is as follows:

| | 2021<br>$'000 | 2020<br>$'000 |
|---|---|---|
| **DTA:** | | |
| -DTA to be recovered in more than 12 months | (5,130) | (4,447) |
| -DTA to be recovered in less than 12 months | (6,400) | (1,550) |
| **DTL:** | | |
| -DTL to be settled in more than 12 months | 2,025 | 2,611 |
| **Net DTA** | **(9,505)** | **(3,386)** |

The movement on the deferred income tax is as follows:

| | 2021<br>$'000 | 2020<br>$'000 |
|---|---|---|
| At beginning of year | (3,386) | (5,174) |
| Movement for the year | (6,041) | 1,879 |
| Unwinding of deferred tax on fair value uplift | (78) | (91) |
| **Net DTA** | **(9,505)** | **(3,386)** |

The deferred tax balances are analysed below:

| | 2019<br>$'000 | Movement<br>$'000 | 2020<br>$'000 | Movement<br>$'000 | 2021<br>$'000 |
|---|---|---|---|---|---|
| **DTA** | | | | | |
| Acquisition | (33,436) | -- | (33,436) | -- | (33,436) |
| Tax losses recognised | (39,476) | -- | (39,476) | -- | (39,476) |
| Tax losses derecognised | 63,550 | 3,365 | 66,915 | (5,533) | 61,382 |
| | **(9,362)** | **3,365** | **(5,997)** | **(5,533)** | **(11,530)** |

| | 2019 | Movement | 2020 | Movement | 2021 |
|---|---|---|---|---|---|
| **DTL** | **$'000** | **$'000** | **$'000** | **$'000** | **$'000** |
| Accelerated tax depreciation and non-current asset impairment | (17,380) | (1,487) | (18,867) | (508) | (19,375) |
| Acquisitions | 19,580 | -- | 19,580 | -- | 19,580 |
| Fair value uplift | 1,988 | (90) | 1,898 | (78) | 1,820 |
| | **4,188** | **(1,577)** | **2,611** | **(586)** | **2,025** |

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. A DTA of $5.5 million have been recognised during 2021 (2020: $3.4 million was derecognised) based on future taxable profits. The Group has unrecognised deferred tax assets amounting to $94.3 million which have no expiry date.

DTL have decreased by $0.6 million as the temporary difference between the accounting values of property, plant and equipment and intangible assets and tax values decreased compared to 2020 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).

- Tax losses – At the end of 2021 the Group had gross tax losses carried forward of $234.6 million (2020: $237.2 million) represented by corporate tax losses in the UK of $23.7 million (2020: $16.6 million) and PPT and Corporate tax losses in Trinidad and Tobago of $210.9 million (2020: $220.6 million). In the UK corporation tax losses may be carried forward indefinitely. Similarly, in Trinidad and Tobago PPT and corporate tax losses may be carried forward indefinitely to reduce the taxes in future years. However, as of 1 January 2020, PPT losses can only be utilised to shelter a maximum of 75 percent of PPT per annum.

## 19 Inventories

| | Crude oil | Materials and supplies | Total |
|---|---|---|---|
| | **$'000** | **$'000** | **$'000** |
| At 1 January 2021 | 67 | 5,200 | 5,267 |
| Impairment (see note 8) | -- | (1,220) | (1,220) |
| Net inventory movement | 29 | (256) | (227) |
| At 31 December 2021 | **96** | **3,724** | **3,820** |
| | | | |
| At 1 January 2020 | 89 | 5,054 | 5,143 |
| Impairment | -- | -- | -- |
| Net inventory movement | (22) | 146 | 124 |
| At 31 December 2020 | **67** | **5,200** | **5,267** |

(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. In the current year there was a total of $1.2 million of impairment of inventory items.

## 20 Trade and Other Receivables

| | Group | | Company | |
|---|---|---|---|---|
| | **2021** | **2020** | **2021** | **2020** |
| | **$'000** | **$'000** | **$'000** | **$'000** |
| **Due within 1 year** | | | | |
| Amounts due from related parties (Note 30 (d)) | -- | -- | 3,372 | 4,418 |
| Trade receivables | 4,641 | 3,357 | -- | -- |
| Less: provision for impairment of trade and intercompany receivables | (6) | (6) | -- | (100) |
| Trade receivables – net | 4,635 | 3,351 | 3,372 | 4,318 |
| Prepayments | 895 | 862 | 175 | 149 |
| VAT recoverable | 4,550 | 2,467 | 25 | 125 |
| Other receivables | 767 | 1,413 | -- | 150 |
| Less: provision for Impairment of other receivables | (100) | (854) | -- | -- |
| | **10,747** | **7,239** | **3,572** | **4,742** |

All trade receivables are with the Group's only customer, Heritage. Ageing analysis of these trade receivables as at 31 December 2021 is as follows:

| | 2021 | 2020 |
|---|---|---|
| | **$'000** | **$'000** |
| Up to 30 days | 4,495 | 3,211 |
| >60 days | -- | -- |
| >180 days | 140 | 140 |
| | **4,635** | **3,351** |

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

| | Group | | Company | |
|---|---|---|---|---|
| | **2021** | **2020** | **2021** | **2020** |
| | **$'000** | **$'000** | **$'000** | **$'000** |
| USD | 3,292 | 4,567 | 3,416 | 4,589 |
| GBP | 169 | 191 | 156 | 252 |

| | | | | |
|---|---|---|---|---|
| TTD | 7,286 | 2,481 | -- | -- |
| | **10,747** | **7,239** | **3,572** | **4,841** |

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** | |
|---|---|---|---|---|
| | **2021** | **2020** | **2021** | **2020** |
| | **$'000** | **$'000** | **$'000** | **$'000** |
| **Trade receivables** | | | | |
| Counterparties without external credit rating: | | | | |
| Existing customers with no defaults in the past | **10,747** | **7,239** | **--** | **--** |

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

The Group applies the IFRS 9 simplified model for measuring expected credit losses ("ECL") using a lifetime expected loss provision for trade and other receivables. The expected loss rates are based on the Group's historical credit losses experienced over a period prior to the period end. The historical loss rates are then adjusted for current and forward-looking information on key macroeconomic factors affecting the Group's customer including GDP, foreign exchange rates, crude oil prices and inflation rates. In calculating an ECL, two default loss rates are established; default loss rate 1 which is calculated through the ageing profiles of sales, and default loss rate 2 which is default loss rate 1 adjusted based on forward looking information.

Having reviewed past payment performance combined with the credit rating of Heritage (and its predecessor, Petrotrin), a Provision matrix was completed to calculate a potential impairment on the receivable balances. Trade receivables that are less than six months past due are not considered impaired and at 31 December 2021, trade receivables of $4.6 million (2020: $3.4 million) were therefore considered to be fully performing.

At the end of 2021 a total of $0.1 million was outstanding from Petrotrin (2020: $0.1 million). An ECL of $0.0 million was applied to the outstanding $0.1 million receivables amount due from Petrotrin.

In June 2021 Trinity renewed its Galeota Block Joint Operating Agreement (JOA) with Heritage. In addition, Heritage and Trinity formed a new agreement to convert Heritage's participating interest in the Galeota Block into an Overriding Royalty with Trinity now having 100% interest in the Galeota Block. Previously, Trinity invested 100% of the funds in capital expenditure towards the Galeota Asset Development and rebilled Heritage's share (via Joint Interest Billings (JIBs)). As at 14 July 2021 all JIBs receivable relating to the Galeota Block was reclassified as capital expenditure. The total amounts converted from JIBs to E&E expenditure as at 14 July 2021 was $2.2 million which consisted of JIBs receivable of $1.4 million (2020: $1 million) and reversal of ECL $0.8 million (2020 ECL: $0.8 million).

For other Joint Interest Billing receivable amounts from Heritage, an ECL of $0.1 million (2020: $0.9 million) was calculated.

## 21 Derivative financial instruments

*Derivative financial assets*

The following table compares the carrying amounts and fair values of the Group's financial assets and financial liabilities as at 31 December 2021.

-

| | **As at 31 December 2021 $'000** | **As at 31 December 2020 $'000** |
|---|---|---|
| Derivative asset | -- | 266 |
| Total | -- | 266 |

The Group considers that the carrying amount of the following financial assets and financial liabilities are a reasonable approximation of their fair value:

- Trade receivables
- Trade payables
- Cash and cash equivalents

*Fair Value Hierarchy*

The level in the fair value hierarchy within which the derivative financial asset is categorised is determined on the basis of the lowest level input that is significant to the fair value measurement.

The derivative financial assets are classified in their entirety into only one of the three levels.

The fair value hierarchy has the following level:

- Level 1 - quoted prices (unadjusted) in active markets for identical assets or liabilities

- Level 2 - inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices)

- Level 3 - inputs for the asset or liability that are not based on observable market data (unobservable inputs).

Level 2 recurring fair value measurements:

| | **As at 31 December 2021 $'000** |
|---|---|
| Opening balance | 266 |
| Opening derivative instrument realised | (266) |
| Closing balance | -- |

*Derivative financial liabilities*

| | **As at 31 December 2021 $'000** | **As at 31 December 2020 $'000** |
|---|---|---|
| Derivative liabilities | 2,883 | -- |
| Total | 2,883 | -- |

On 31 December 2021 the crude derivative contracts were valued using a Mark to Market report. The report provides estimated forward looking values on the existing crude derivatives held at 31 December 2021.

## 22 Cash and Cash Equivalents

| | **Group** | | **Company** | |
|---|---|---|---|---|
| | **2021 $'000** | **2020 $'000** | **2021 $'000** | **2020 $'000** |
| Short term investment | 2,449 | 4,055 | 2,449 | 4,055 |
| Cash and cash equivalents | 15,863 | 16,182 | 659 | 262 |
| | **18,312** | **20,237** | **3,108** | **4,317** |

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.

## 23 Share Capital and Share Premium

**Group**

| | Number of shares | Ordinary shares $'000 | Share premium $'000 | Total $'000 |
|---|---|---|---|---|
| As at 1 January 2021 | 483,594,288 | 97,692 | 139,879 | 237,571 |
| Share reduction and cancellation of deferred shares | (444,714,857) | -- | -- | -- |
| Capital reduction | -- | (97,308) | (139,879) | (237,187) |
| 2020 Share Issue – Nominal value [1] | -- | 5 | -- | 5 |
| **As at 31 December 2021** | **38,879,431** | **389** | **--** | **389** |

During 2021 the Company undertook a Capital Reorganisation to enable the Company to pay dividends, or effect share buybacks, when it is considered prudent to do so. This process comprised:

1. a Consolidation of every 10 Existing Ordinary Shares into one Consolidated Ordinary Share
2. an immediate Sub-Division of each of those Consolidated Ordinary Shares into one New Ordinary Share and one New Deferred Share; and
3. a Capital Reduction by way of both the cancellation of the Existing Deferred Shares and the New Deferred Shares and the cancellation of the Company's Share Premium Account.

- On 18 June 2021 the Share Consolidation and Sub-Division reduced the high number of existing Ordinary Shares in issue and the Sub-Division retained the nominal value of $0.01 each per New Ordinary Share, which is same as the previous nominal value of each of the existing Ordinary Shares.
- On 14 July 2021 the Capital Reduction effectively cancelled the entire Share Premium Account of the Company as well as the Existing Deferred Shares and new Deferred Shares created following the Share Consolidation and Sub-Division.
- The Capital Reorganisation was completed on 14 July 2021 subsequent to the UK Court approval of the Capital Reduction.
- Following the Capital Reduction, the issued ordinary share capital of the Company stood at 38,879,431 ordinary shares of $0.01 each, with no Ordinary Shares held in treasury. The total number of voting rights in the Company also remains at 38,879,431.

[1] - In 2020, 4,745,057 shares (pre-consolidation) were issued at nil value to certain employees who exercised options that vested in respect to one off LTIP awards made in 2017. In 2021 the nominal value of these shares, being US$0.05 million, were paid to the Company and as part of the Capital Reduction, $0.05 million was transferred to retained earnings and the remaining US$0.0 million was treated as share capital.

## 24 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 2021 the Group had in place share-based payment arrangements for its employees and Executive Directors, the LTIP. The Share Option Plan referenced below is fully vested and expensed. The current year charge for share based payments are solely in relation to the LTIP arrangements shown below, with further details of each scheme following:

| | 2021 | 2020 |
|---|---|---|

| | $'000 | $'000 |
|---|---|---|
| At 1 January | 14,764 | 14,328 |
| Capital Reduction | (11,485) | |
| Share based payment expense: | | |
| LTIP exercised | -- | (527) |
| LTIP expense | 505 | 963 |
| At 31 December | **3,784** | **14,764** |

**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 expire in 2022 and 2023. The table below gives details:

| Grant-Vest | Expiry Date | Exercise price per Share Option | 2021 Number of Options | Exercise price per Share Option | 2020 Number of Share Options |
|---|---|---|---|---|---|
| 2012-2015 | 2022 | GBP 8.60 | 168,554 | GBP8.60 | 168,554 |
| 2013-2016 | 2023 | GBP 12.00 | 28,954 | GBP12.00 | 28,954 |
| | | | 197,508 | | 197,508 |

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 11.90 | GBP 12.00 |
| Average Exercise price | GBP 12.00 | GBP 8.90 |
| 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 the EMT to deliver long-term shareholder returns. Under the plan, participants are granted options which only vest if certain performance conditions 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 Options are exercisable at nil cost by the participants.

**2017 LTIPs**

One off LTIP awards were granted in August 2017 over 2,541,600 ordinary shares and in June 2020 over a further 142,296 ordinary shares (the "2017 LTIP Awards"). The 2017 LTIP awards, which ordinarily vest on 30 June 2022, partially vested on 30 June 2020 and 30 June 2021, subject to meeting performance targets relating to the following:

- In respect of 70% of the award, the Company's share price growth from the 2017 placing price of 49.8 pence per share. If the three-month volume-weighted price ("VWAP") at the testing date is 350 pence or more per share, this part of the award will vest in full. If the VWAP at the testing date is 49.8 pence per share or less, this part of the award will not vest at all. If the VWAP at the testing date is between 49.8 pence and 350 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 in 2018; and

- In respect of 10% of the award, redemption of all the Convertible Loan Notes ("CLN") issued in January 2017 before the second anniversary of their issue. All of the CLNs were redeemed 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, LTIP Award may vest in full or in part on 30 June 2020 or 2021 with the appropriate charge being taken over the vesting period. 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 were as follows:

| | | |
|---|---|---|
| Grant Date | 24 August 2017 | 30 June 2020 |
| Share price at grant date | GBP 107.50p | GBP 79.00p |
| Exercise price | GBP 0.00 | GBP 0.00 |
| Expected volatility | 73.3% | 84.9% |
| Risk-free interest rates | 0.44% | (0.07%) |
| Expected dividend yields | 0% | 0% |
| Vesting period 1 | 30 June 2020 | -- |
| Vesting period 2 | 30 June 2021 | -- |
| Vesting period 3 | 30 June 2022 | 30 June 2022 |

**2019 LTIPs**

In January 2019 Options over 282,400 ordinary shares and in May 2019 Options over 383,282 ordinary shares were granted under the LTIP in accordance with the policy announced to the market on 25 August 2017. The January 2019 LTIP awards vested 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.

| 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%) and above | 100% of the maximum award will vest | 100% of the maximum award will vest |

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. The amounts stated above represent the maximum possible opportunity.

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 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 were as follows:

| | January 2019 LTIPs | May 2019 LTIPs |
|---|---|---|
| Grant Dates | 2 January 2019 | 9 May 2019 |
| Share price at grant dates | GBP167.7p | GBP146.6p |
| 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 |

**2020 LTIPs**

On 25 June 2020 and 30 October 2020 Options over a total of 481,586 ordinary shares were granted under the LTIP in accordance with the policy announced to the market on 25 August 2017 to members of the EMT in respect of the performance of the Company in the financial year ended 31 December 2019. These LTIP awards will vest on 2 January 2023, subject to meeting the performance criteria set out in the table below and continued employment in the Company.

| Performance | Vesting |
|---|---|
| Below the Median | None of the award will vest |

| | |
|---|---|
| Median (50$^{th}$ percentile) | 30% of the maximum award will vest |
| Between Median and Upper Quartile | Straight Line basis between these points |
| Upper Quartile (75%) | 100% of the maximum award will vest. |
| Above the Upper Quartile | 100% of the maximum award will vest |

The LTIP Awards are subject to the achievement of relative Total Shareholder Return ("TSR") performance targets measured over a three-year performance period ending on 31 December 2022. The amounts stated above represent the maximum possible opportunity.

The total fair value at grant date of the 2020 LTIP awards was $0.4 million and this will be pro-rated and expensed over the vesting period. 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 2020 LTIP awards granted during the period were as follows:

| | **June 2020 LTIPs** | **October 2020 LTIPs** |
|---|---|---|
| Grant Dates | 25 June 2020 | 30 October 2020 |
| Share price at grant dates | GBP79.00p | GBP77.00p |
| Exercise price | GBP0.00 | GBP0.00 |
| Expected volatility | 84.9% | 84.9% |
| Risk-free interest rates | (0.07%) | (0.07%) |
| Expected dividend yields | 0% | 0% |
| Vesting dates | 2 January 2023 | 2 January 2023 |

**2021 LTIPs**

On 13 August 2021, Options over a total of 325,000 ordinary shares were granted under the LTIP in accordance with a revised LTIP scheme (the Revised LTIP") to members of the EMT in respect of the performance of the Company in the financial year ended 31 December 2020. These LTIP awards will vest on 1 January 2024, subject to meeting the performance criteria set and continued employment in the Company.

The performance targets set for the 2021 Annual LTIP Awards will be measured considering both the Company's absolute TSR performance and the Company's relative TSR performance over a three-year period, commencing 1 January 2021. TSR calculations will be determined by reference to the volume weighted three-month average price prior to the start and end of the measurement period (with the starting average price adjusted for the Share Consolidation). The three-month volume weighted average price at the start of the performance period for the 2021 Annual LTIP Award was 88p (adjusted for the Share Consolidation).

The performance targets provide that:

- No portion of a distinct one-half of the 2021 Annual LTIP Award (the "Absolute TSR Part") may vest unless the Company's compound annual growth rate of TSR over the performance period is at least 10% p.a., for which 30% of the Absolute TSR Part may vest, rising on a straight line basis for full vesting of the Absolute TSR Part if the Company's compound annual growth rate of TSR over the performance period equals or exceeds 25% p.a.

- No portion of the other distinct one-half of the 2021 Annual LTIP Award (the "Relative TSR Part") may vest unless the Company's TSR over the performance period ranks at least median relative to the TSR performance within a comparator group of companies, for which 30% of the Relative TSR Part may vest, rising on a straight line basis for full vesting of the Relative TSR Part if the Company's TSR over the performance period ranks upper quartile or better relative to the TSR performance within a comparator group.

However, an underpin term applies to the Relative TSR Part which provides that, regardless of relative TSR performance, no vesting may ordinarily accrue in respect of the Relative TSR Part unless the Company's compound annual growth rate of TSR over the performance period is at least 10% per annum.

The total fair value at grant date of the 2020 LTIP awards was $0.7 million and this will be pro-rated and expensed over the vesting period. 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 2021 LTIP awards granted during the period were as follows:

| | **August 2021 LTIPs** |
|---|---|
| Grant Date | 13 August 2021 |
| Share price at grant dates | GBP146.00p |
| Exercise price | GBP0.00 |
| Expected volatility | 6.3% |
| Risk-free interest rates | (0.20%) |
| Expected dividend yields | 0% |
| Vesting dates | 1 January 2024 |

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

| | **2021 Average exercise price per Share Option** | **Number of Options** | **2020 Average exercise price per Share Option** | **Number of Options** |
|---|---|---|---|---|
| At 1 January | GBP 0.00 | 3,156,299 | GBP 0.00 | 3,178,982 |
| Forfeited | GBP 0.00 | (100,000) | GBP 0.00 | (172,059) |
| Granted[1] | GBP 0.00 | 325,000 | GBP 0.00 | 623,882 |
| Exercised[2] | GBP 0.00 | -- | GBP 0.00 | (474,506) |
| At 31 December | GBP 0.00 | 3,381,299 | GBP 0.00 | 3,156,299 |

1 Weighted average fair value of LTIPs granted GBP 0.70

2 Weighted average share price at the date of exercise GBP 0.80

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

| **Grant-Vest** | **Expiry date** | **Exercise price** | **2021** | **2020** |
|---|---|---|---|---|
| 24/8/2017 – 30/6/2022 | 24/8/2027 | GBP 0.00 | 2,103,032 | 2,103,032 |
| 2/1/2019 – 1/1/2021 | 1/1/2023 | GBP 0.00 | 252,510 | 252,510 |
| 9/5/2019 – 2/1/2022 | 2/1/2024 | GBP 0.00 | 319,171 | 319,171 |
| 25/6/2020 – 2/1/2023 | 2/1/2025 | GBP 0.00 | 381,586 | 481,586 |
| 13/8/2021 – 31/12/2023 | 2/1/2025 | GBP 0.00 | 325,000 | -- |

## 25 Merger and Reverse Acquisition Reserves

| | **Reverse Acquisition Reserve $'000** | **Merger Reserve $'000** | **Total $'000** |
|---|---|---|---|
| At 1 January 2021 | (89,268) | 75,467 | (13,801) |
| Capital re-organisation/reduction | -- | (75,467) | (75,467) |
| Translation differences | -- | -- | -- |
| **At 31 December 2021** | **(89,268)** | **--** | **(89,268)** |
| At 1 January 2020 | (89,268) | 75,467 | (13,801) |
| **At 31 December 2020** | **(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.

## 26 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, Impairment and Exceptional Items for the period, adjusted for DD&A, ILFA, SOE, FX Gain/(Loss) and FV Derivative Instruments.

The Group presents Adjusted EBITDA as it is used in assessing the Group's growth and operational performance 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:

| | 2021<br>$'000 | 2020<br>$'000 |
|---|---|---|
| Operating Profit Before SPT, PT, Impairment and Exceptional Items and Covid-19 expense | 10,019 | 2,965 |
| Covid-19 expense | (669) | -- |
| DD&A (note 13 - 15) | 7,428 | 8,174 |
| ILFA (note 20) | (754) | 252 |
| SOE (note 24) | 626 | 963 |
| FX (loss)/gain | 14 | (7) |
| FV Derivative Instruments (note 6) | 3,149 | (266) |
| Adjusted EBITDA | 19,813 | 12,081 |

| | $'000 | $'000 |
|---|---|---|
| Weighted average ordinary shares outstanding - basic | 38,879 | 38,623 |
| Weighted average ordinary shares outstanding - diluted | 41,969 | 41,780 |

| | $ | $ |
|---|---|---|
| Adjusted EBITDA per share – basic (note 11) | 0.51 | 0.31 |
| Adjusted EBITDA per share - diluted (note 11) | 0.47 | 0.29 |

Adjusted EBITDA after current taxes (*the impact of SPT, PT and PPT/UL*) is calculated as follows:

| | 2021<br>$'000 | 2020<br>$'000 |
|---|---|---|
| Adjusted EBITDA | 19,813 | 12,081 |
| SPT | (5,074) | 153 |
| PT | 1,516 | (532) |
| PPT/UL | (1,375) | (1,143) |
| Adjusted EBITDA After Current Taxes | 14,880 | 10,559 |

| | '000 | '000 |
|---|---|---|
| Weighted average ordinary shares outstanding - basic | 38,879 | 38,623 |
| Weighted average ordinary shares outstanding - diluted | 41,969 | 41,780 |

| | $ | $ |
|---|---|---|
| Adjusted EBITDA After Current Taxes per share - basic | 0.38 | 0.27 |
| Adjusted EBITDA After Current Taxes per share - diluted | 0.35 | 0.25 |

**Restatement 2020 balance*

Comparative figures have been recalculated to conform with changes in presentation in the current year. The comparative figures were recalculated to show the impact on the Adjusted EBITDA per share resulting from the 10:1 share consolidation which reduced the number of ordinary shares from 388,794,303 to 38,879,430 (see note 23). The impact of the restatement is summarised below:

| | 31 December 2020 | 31 December 2020 |
|---|---|---|

| | $ Restated | $ Prior period |
|---|---|---|
| *Adjusted EBITDA* | | |
| Adjusted EBITDA per share - basic | 0.31 | 0.03 |
| Adjusted EBITDA per share - diluted | 0.29 | 0.03 |
| *Adjusted EBITDA after Current Taxes* | | |
| Adjusted EBITDA after Current Taxes per share - basic | 0.27 | 0.03 |
| Adjusted EBITDA after Current Taxes per share - diluted | 0.25 | 0.03 |

## 27 Provision for Other Liabilities

| **(a) Non-current:** | **Decommissioning provision $'000** | **Closure of pits[1] $'000** | **Total $'000** |
|---|---|---|---|
| **Year ended 31 December 2021** | | | |
| Opening amount as at 1 January 2021 | 45,405 | 470 | 45,875 |
| Unwinding of discount (Note 9) | 1,222 | -- | 1,222 |
| Revision to estimates (Note 13) | 8,407 | -- | 8,407 |
| Decommissioning contribution | 195 | -- | 195 |
| Translation differences | (9) | -- | (9) |
| **Closing balance at 31 December 2021** | **55,220** | **470** | **55,690** |
| **Year ended 31 December 2020** | | | |
| Opening amount as at 1 January 2020 | 44,330 | -- | 44,330 |
| Unwinding of discount (Note 9) | 1,221 | -- | 1,221 |
| Revision to estimates | (152) | -- | (152) |
| Translation differences | 6 | | 6 |
| **Closing balance at 31 December 2020** | **45,405** | **--** | **45,405** |

**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 stations and pipeline infrastructures. The amounts are calculated based on the provisions of existing contractual agreements with Heritage and MEEI. Furthermore, liabilities for decommissioning costs are recognised when the Group has an obligation to dismantle and remove a facility or an item of plant and to restore the site on which it is located, and when a reasonable estimate of that liability can be made. An obligation for decommissioning may also crystallise during the period of operation of a facility through a change in legislation or through a decision to terminate operations.

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

a. Core inflation rate – 2.40% (2020: 2.00%)
b. Risk free rate – 1.80% - 2.20% (2020: 2.42% - 3.17%)
c. Estimated market value/decommissioning cost
d. Estimated life of each asset

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

[1] There was a change in estimate whereby the Closure of pits provision was reclassified from current to non-current

liabilities for the period to 31 December 2021 as management obtained new information in the current period estimating that the liability may extend beyond 12 months.

**(b) Current:**

| | Litigation claims $'000 |
|---|---|
| **Opening and Closing balance 2021** | **46** |
| | |
| **Opening and Closing balance at 2020** | **46** |

**Litigation claims**

In 2021 there was a litigation settlement for $0.0 million and increase in the provisions for $0.0 million.

**Closure of Pits**

In 2020 there was a decrease in the provision of $0.0 million relating to the revision to 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.

## 28 Trade and Other Payables

| | Group | | Company | |
|---|---|---|---|---|
| **Current** | **2021 $'000** | **2020 $'000** | **2021 $'000** | **2020 $'000** |
| Trade payables | 2,274 | 2,024 | 88 | 130 |
| Accruals | 4,486 | 3,793 | 239 | 351 |
| Other payables | 492 | 471 | -- | -- |
| SPT & PT | 1,562 | 1,515 | -- | -- |
| | **8,814** | **7,803** | **327** | **481** |

## 29 Bank overdraft

| | 31 December 2021 $'000 | 31 December 2020 $'000 |
|---|---|---|
| Bank Overdraft | 2,700 | 2,700 |
| | **2,700** | **2,700** |

In 2020, an on-demand operating (overdraft) line of $2.7 million was established with FirstCaribbean International Bank (Trinidad & Tobago) Limited ("CIBC"). Details of the overdraft facility:

- Description: Demand revolving credit
- Interest Rate: United States dollar prime rate minus 4.05% per annum, effective rate 4.95%, floor rate of 3.95%. Interest is payable monthly.
- Repayment: Upon demand at CIBC's discretion.
- Debenture: Floating charge debenture, giving the lender a first ranking floating charge over inventory and trade receivables only.
- Covenant: Current Ratio not less than 1.25:1.

On 2 April 2020 the Company drew down the $2.7 million in full. For the year ended 31 December 2021, the credit limit was increased to $5 million but no further amounts were drawn.

## 30 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) Transfers of funds from related parties

| | Company | |
|---|---|---|
| | **2021** | **2020** |
| | **$'000** | **$'000** |
| ***Company subsidiaries:*** | | |
| Trinity Exploration and Production Services | 856 | -- |
| Trinity Exploration & Production (UK) Limited | 8 | 10 |
| Trinity Exploration and Production (Galeota) Limited | 659 | 26 |
| Bayfield Energy Limited | 19 | 61 |
| Oilbelt Services Limited | 1,659 | 170 |
| Trinity Exploration and Production (Trinidad and Tobago) Limited | 393 | -- |
| Galeota Oilfield Services Limited | -- | 3 |
| Trinity Exploration and Production Services Limited (UK) Limited | 30 | 899 |
| Transfer of funds | 73 | -- |
| | **3,697** | **1,169** |

(b) Transfer of funds to related parties

| | Company | |
|---|---|---|
| | **2021** | **2020** |
| | **$'000** | **$'000** |
| ***Company subsidiaries:*** | | |
| Trinity Exploration and Production Services | (70) | (473) |
| Bayfield Energy Limited | (100) | -- |
| Trinity Exploration and Production Services Limited (UK) Limited | (2,063) | --- |
| | **(2,233)** | **(473)** |

Related party transactions comprise of the transfer of funds to and from related parties which are payable on demand. Positive balances indicate increase in funds transferred to the entities, while negative balances indicate repayment to entities.

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

| | Group | |
|---|---|---|
| | **2021** | **2020** |
| | **$'000** | **$'000** |
| Salaries and short-term employee benefits | 1,337 | 1,219 |
| Post-employment benefits | 27 | 26 |
| Share-based payment expense | 305 | 469 |
| | **1,669** | **1,714** |

(d) Year-end balances arising from transfer to and from related parties

| | Company |
|---|---|

| | 2021 $'000 | 2020 $'000 |
|---|---|---|
| **Receivables from related parties:** | | |
| Trinity Exploration and Production Services Limited | -- | 408 |
| Trinity Exploration & Production (UK) Limited | 28 | 28 |
| Trinity Exploration and Production (Galeota) Limited | -- | 159 |
| Bayfield Energy Limited | 192 | 104 |
| Oilbelt Services Limited | -- | 1,029 |
| Galeota Oilfield Services Limited | -- | 4 |
| Trinity Exploration and Production (Trinidad and Tobago) Limited | 22 | 414 |
| Trinity Exploration and Production Services (UK) Limited | 3,129 | 2,272 |
| Employee Benefit Trust (See note 1) | 73 | -- |
| **Total intercompany receivables (Note 20)** | **3,443** | **4,418** |
| Less: provision for impairment of intercompany receivables | (71) | (100) |
| **Closing intercompany receivables (Note 20)** | **3,372** | **4,318** |

**Company**

- The receivables from related parties arise mainly from inter-group recharges. The receivables are unsecured and bear no interest. An ECL provision was calculated $0.1 million (2020: 0.1 million).

| | Company | |
|---|---|---|
| | 2021 $'000 | 2020 $'000 |
| **Payables to related parties:** | | |
| Trinity Exploration and Production Services Limited | 167 | -- |
| Trinity Exploration and Production Services (UK) Limited | 7 | |
| Trinity Exploration and Production (Galeota) Limited | 112 | -- |
| Oilbelt Services Limited | 495 | -- |
| **Total intercompany payables** | **781** | **--** |

## 31 Taxation Payable

| | 2021 $'000 | 2020 $'000 |
|---|---|---|
| Taxation payable | | |
| PPT | -- | 144 |
| UL | -- | 58 |
| | -- | 202 |

Trinidad and Tobago statutory petroleum profit tax ("PPT") and unemployment levy ('UL") are a combined rate of 55% of taxable income. PPT has a tax charge of 50%, while UL has a tax charge of 5% on taxable profits.

## 32 Financial Instruments by Category

At 31 December 2021 and 2020, the Group held the following financial assets at amortised cost:

| | Group | | Company | |
|---|---|---|---|---|
| | 2021 $'000 | 2020 $'000 | 2021 $'000 | 2020 $'000 |
| Trade and other receivables – current* | 5,302 | 3,910 | 200 | 424 |
| Abandonment fund – non current | 4,021 | 3,490 | -- | -- |

| | | | | |
|---|---|---|---|---|
| Intercompany | -- | -- | 3,372 | 4,318 |
| Cash and cash equivalents | 18,312 | 20,237 | 3,108 | 4,317 |
| | **27,635** | **27,637** | **6,680** | **9,059** |

*Note (*): Excludes prepayments and VAT recoverable*

At 31 December 2021 and 2020, the Group held the following financial liabilities at amortised cost:

| | Group | | Company | |
|---|---|---|---|---|
| | **2021** | **2020** | **2021** | **2020** |
| | **$'000** | **$'000** | **$'000** | **$'000** |
| Accounts payable and accruals | 8,814 | 7,803 | 327 | 481 |
| Intercompany | -- | -- | 781 | -- |
| Bank overdraft | 2,700 | 2,700 | -- | -- |
| | **11,514** | **10,503** | **1,108** | **481** |

At 31 December 2021 and 2020, the Group held the following financial asset at fair value through profit or loss:

| | Group | | Company | |
|---|---|---|---|---|
| | **2021** | **2020** | **2021** | **2020** |
| | **$'000** | **$'000** | **$'000** | **$'000** |
| Derivative financial asset | -- | 266 | -- | 266 |
| | **--** | **266** | **--** | **266** |

| | Group | | Company | |
|---|---|---|---|---|
| | **2021** | **2020** | **2021** | **2020** |
| | **$'000** | **$'000** | **$'000** | **$'000** |
| Derivative financial liability | 2,883 | -- | 2,883 | -- |
| | **2,883** | **--** | **2,883** | **--** |

## 33 Commitments and Contingencies

### a) Commitments

There are commitments for decommissioning costs of the wells and facilities under the Group's agreements with Heritage, which have been provided for as described in Note 27: Provision for other liabilities.

### b) Contingent Liabilities

i) The West Coast Point Ligoure, Guapo Bay and Brighton Marine Outer ("PGB") licences and the Farm-Out Agreement for the Tabaquite Block (held by Coastline International Inc.) have expired. There may be additional liabilities and commitments arising when new agreements are finalised, but these cannot be presently quantified until new agreements are available.

ii) Parent Company Guarantee:

a) PGB - A Letter of Guarantee has been established in substance over the PGB Block where a subsidiary of Trinity is obliged to carry out a Minimum Work Programme to the value of $8.4 million. A clause within the Letter of Guarantee implies that the 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. The PGB licence has expired.

b) Galeota - A Letter of Guarantee has been established in substance over the Galeota Block where a subsidiary of Trinity is obliged to carry out a Minimum Work Programme to the value of $0.9 million. A clause within the Letter of Guarantee implies that the Guarantor may reduce the Guarantee Sum available for payment to the MEEI under the Letter of Guarantee on an obligation by obligation basis provided the subsidiary of Trinity delivers to the Guarantor a certificate duly issued and signed by the Minister of the

MEEI. The Letter of Guarantee was effective from 14 July 2021 until the earlier of performance of Minimum Work Programme or the Guarantor has paid the Guarantee amount.

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 condensed consolidated financial statements.

iv) On 1 December 2021, Trinity acquired the PS-4 Block Lease Operatorship Sub-Licence. As part of the lease agreement, a Performance Bond of $0.13 million is required to be executed with Heritage. At 31 December 2021, the Performance Bond was not finalised and is expected to be completed subsequent to the year-end.

## 34 Employee Costs

| | Group | | Company | |
|---|---|---|---|---|
| **Employee costs for the Group during the year** | **2021 $'000** | **2020 $'000** | **2021 $'000** | **2020 $'000** |
| Wages and salaries | 8,625 | 6,266 | 1,170 | 910 |
| Other pension costs | 372 | 358 | -- | -- |
| Share based payment expense (Note 22) | 673 | 963 | 94 | 248 |
| | **9,670** | **7,587** | **1,264** | **1,158** |

| | | | | |
|---|---|---|---|---|
| **Average monthly number of people (including Executive and Non-Executive Directors') employed by the Group** | **2021 number** | **2020 number** | **2021 number** | **2020 number** |
| Executive and Non-Executive Directors | 6 | 6 | 6 | 6 |
| Administrative staff | 95 | 85 | -- | -- |
| Operational staff | 144 | 131 | -- | -- |
| | **245** | **222** | **6** | **6** |

## 35 Events after the Reporting Year

1. The Company implemented crude derivatives over the Group's monthly production in 2021 and 2022. The derivative protection currently in effect for 2022 is as follows:

| Type of Derivatives | Index | Sell Put | Buy Put | Sell Call | Buy Call | Production | Effective Date | Expiry Date | Execution Date | Premium USD MM |
|---|---|---|---|---|---|---|---|---|---|---|
| | | US$/bbl | US$/bbl | US$/bbl | US$/bbl | Monthly Barrels | | | | |
| 3-Way Cost Collar | ICE Brent | 50.00 | 60.00 | 66.90 | - | 10,000 | 1-Jan-22 | 30-Jun-22 | 04-Mar-21 | |
| 3-Way Cost Collar | ICE Brent | 50.00 | 60.00 | 74.40 | - | 12,500 | 1-Jan-22 | 31-Dec-22 | 02-Jun-21 | |
| 4-Way Cost Collar | ICE Brent | 59.00 | 68.00 | 72.00 | 82.00 | 15,000 | 1-Jan-22 | 30-Jun-22 | 05-Jul-21 | |
| 3-Way Cost Collar | ICE Brent | 40.00 | 50.00 | 80.50 | - | 15,000 | 1-Jan-22 | 31-Dec-22 | 27-Aug-21 | |
| Put Spread Option | ICE Brent | 40.00 | 50.00 | - | - | 15,000 | 1-Jul-22 | 31-Dec-22 | 14-Jan-22 | 0.15 |

2. On 24 February 2022, Russian forces invaded Ukraine, causing wide-ranging sanctions to be applied against the Russian regime by the US, EU and other major economies. The event caused both Brent and WTI oil prices to soar, peaking well above $100 per bbl into March 2022. The impact of increased oil prices has mainly positively impacted the Group's crude oil revenue but negatively impacted derivative expenses. Overall, whilst there has been no

significant adverse impact to the Group, Management continues to closely monitor the event's impact as it unfolds.

3. In 2021 Trinity engaged with a range of potential partners as part of the Galeota farm down process. The Company on 3 May 2022 indicated, whilst initial feedback has been encouraging, a number of participants have informed the Company that they are unable to fully assess the economics of the opportunity at Galeota without clarity on the expected reforms to Supplemental Petroleum Tax ("SPT"), which are currently being considered by the Government of Trinidad and Tobago ("GORTT") and which were initially expected to have been confirmed sooner than now appears likely. Pending SPT reform, which management still expects to happen, the Company has decided to pause the Galeota farm down process. This will enable the Company to seek the best value proposition for Galeota when the GORTT's fiscal reforms have been confirmed.

   In the interim, the Company will continue to refine its plans for Galeota. In particular, it will advance preparations for exploiting the 9.77mmstb of 2P reserves remaining in the Trintes field.