2022 Preliminary Unaudited Full Year Results

25 April 2023—Singapore: Jadestone Energy plc (AIM:JSE) ("Jadestone" or the "Company"), an independent oil and gas production company and its subsidiaries (the "Group"), focused on the Asia-Pacific region, reports today its preliminary[1] unaudited consolidated financial statements (the "Financial Statements"), as at and for the financial year ended 31 December 2022. Management will host a conference call today at 9:00 a.m. UK time, details of which can be found in the release below.

Paul Blakeley, President and CEO commented:

"2022 was an extremely frustrating year operationally, one which largely overshadowed the underlying progress made in a number of key strategic areas. The first half of the year validated our strategy at work, as we generated significant operating cash flow, building our cash balance to a record high of US$162 million by mid-year. The second half however highlighted the over-reliance on Montara for operational and financial performance, highlighting that we are vulnerable to single events on this asset.

Since we became operator of Montara in 2019, we have been undertaking an ongoing programme to revitalise the asset through a systematic process of inspection, remediation and repair. Progress has been impacted by COVID-related manning restrictions over the past 18 months, that caused delays to this programme, and which frustratingly contributed to the unplanned event in July when a small hole in storage tank 2C was detected, a tank that was scheduled to be next in the inspection programme.

We have since undertaken an extensive 8-month shutdown, which has allowed us to address required regulatory actions, and carried out a detailed inspection of critical areas of the FPSO and the necessary repairs and maintenance to restart production. This was the right thing to do notwithstanding the major short-term impact on the business, and our clear focus from now on is to ensure to the best of our ability that there will be no further unplanned events of this nature at Montara. Since restarting production in March 2023, Montara has performed in line with expectations, producing from three wells at c.4,700 bbls/d, with additional wells becoming available for production in the coming weeks and more cargo tanks being returned to service in due course.

Over the past eight months, Montara has stress tested our resilience, and I am very proud of the way in which the whole team has responded in these difficult circumstances to work through the issues and bring the asset back on stream.

However, the past 8 months, although challenging, has also demonstrated that we have the right strategy, highly cash generative with quick pay-back, adding to our production portfolio in a disciplined way. In doing this, we are repositioning the portfolio to ensure this won't be repeated, so while Montara was 80% of our production in mid-2021, it is expected to be 20% of our production by mid-2024. Over the same period, we will have expanded the business from just two producing assets to seven in multiple countries and jurisdictions, providing the portfolio diversity that will insulate the company from the impact of such events in the future, a benefit usually exclusive to the majors and one that will differentiate us from our peers.

Despite the hiatus at Montara, our robust business model allowed us to end 2022 with an increased cash balance over the 12-month period and a US$9 million profit for the year. This was delivered against a backdrop of an extensive capital programme, a share buy-back of approximately US$18 million, completion of two acquisitions including BP's interest in the highly attractive CWLH assets on the North West shelf, and commencement of the Akatara gas field development, our largest ever organic project, onshore Indonesia.

Due to a combination of first quarter 2023 liftings being back-end loaded and high activity levels throughout our portfolio, cash available by end March 2023 had reduced to US$64 million, with US$29m of debt drawn from the Interim Facility to fund the Sinphuhorm acquisition.

With respect to the RBL, we have one international bank credit approved and three others in the credit approval process, and expect the facility to close in May 2023 once customary conditions precedent are satisfied. We also anticipate approval from NOPTA on the CWLH title transfer to Jadestone in May, which is required to draw down the RBL. The RBL would restore our capital flexibility and even though we maintain a high level of reinvestment in the business, the highly cash generative nature of our portfolio, particularly after Akatara comes onstream, should see us approaching a net cash position around the end of 2024 based on expected operating performance and current oil prices. Importantly, the RBL will also facilitate the funding of further acquisitions of producing assets. Our intention as previously, will be to utilise some hedging to help secure the RBL repayment schedule, while still retaining a significant exposure to oil price upside. In line with our approach to the final 2021 dividend, a recommendation on the final dividend for 2022 will be made when our audited accounts are released in late-May 2023.

In addition to the recently acquired gas production at Sinphuhorm, we will add the fixed price gas that is expected onstream at Akatara in the first half of next year, both of which give increased reliability to future cash flows.

Strong growth in the business is emphasised by the 45% increase in 2P reserves at year-end, circa six times production replacement, and it is worth recognising, that we have maintained asset reserves at Montara, reinforcing the principle that despite the shut-down, reserves and cash flows have been deferred and not lost. This provides a lot of encouragement for the future; our company has been proven to be resilient through the challenges we have faced and we have strengthened the business through both product and portfolio diversification, a strategy we will continue to pursue.

2023 should be a promising year for Jadestone with the Akatara project in the Lemang PSC on schedule and within budget, an exciting four well programme at East Belumut, closing of Sinphuhorm and the potential to add to the portfolio through further acquisitions.

I'm extremely grateful to the people within Jadestone who have worked tirelessly across the business to get us back on track, and despite a period of significant challenge imposed by the events of the past several months, have never wavered from doing the right thing. It has been a challenging year, lessons have been learned and implemented, but we look forward with renewed confidence to the future"

Paul Blakeley

EXECUTIVE DIRECTOR, PRESIDENT AND CHIEF EXECUTIVE OFFICER

[1] The audited financial results will be released on 25 May 2023 together with the release of the Group's FY2022 Annual Report.

2022 SUMMARY

USD'000 except where indicated	2022	2021 (Restated)[1]
Production, boe/day	11,487	12,545
Realised oil price per barrel of oil equivalent (US$/boe)[1]	103.85	74.34
Realised gas price per thousand standard cubic feet (US$/mscf)	1.63	1.61
Revenue	421,602	340,194
Production costs	(250,700)	(211,896)
Operating costs per barrel of oil equivalent (US$/boe)[2]	37.49	26.22
Adjusted EBITDAX[2]	161,929	142,242
Profit/(Loss) after tax	8,522	(17,073)
Earnings/(Loss) per ordinary share: basic & diluted (US$)	0.02	(0.04)
Operating cash flows before movement in working capital	158,148	91,249
Capital expenditure	82,876	55,996
Net cash[2]	123,329	117,865

Operational and financial summary

- Proven and probable reserves at year-end 2022 totalled 64.8 mmboe, a 45% increase compared to the reserves at year-end 2021 of 44.7 mmbbls, representing a reserves replacement of 579%, reflecting the conversion of Akatara gas field contingent resources to reserves and addition of the non-operating working interest in the Cossack, Wanaea, Lambert and Hermes ("CWLH") Assets, offset by production and modest technical revisions during the year;
- Full year production decreased by 8% to 11,487 boe/d (2021: 12,545 bbls/d), due to Montara being shut-in for tank repairs from August 2022 and the FPSO class suspension at the non-operated Peninsular Malaysia ("PenMal") Assets. This was offset by higher annualised production at the operated PenMal Assets due to a full year of operations in 2022 and two months' contribution from the CWLH Assets;
- Total lifted volumes in 2022 decreased 7% to 4.3 mmboe (included lifted volumes of 0.7 mmbbls from the CWLH Assets), compared to 4.7 mmboe in 2021, reflecting lower production at Montara and the non-operated PenMal Assets;
- Total revenue increased 24% to US$421.6 million (2021: US$340.2 million) due to a 40% increase in realised prices, partly offset by a 7% reduction in lifted volumes;
- The average realised price for the year was US$103.85/bbl in 2022 (2021: US$74.34/bbl), a 40% increase year-on-year. The average realised price premium was US$7.81/bbl for 2022 (2021: US$3.39/bbl);
- Total production costs of US$250.7 million, compared to US$211.9 million in 2021, due to:
    - The inclusion of US$37.8 million in 2022 associated with the CWLH Assets acquired in November 2022, consisting of US$3.7 million cash operating costs and an additional US$34.1 million of non-cash inventory movements, relating to moving from a significant underlift position to an overlift position following the lifting which occurred in mid-November 2022;
    - A full year of operations and supplementary payments at the PenMal Assets following their acquisition in August 2021, whereby the supplementary payment also increased due to higher realised oil prices;
    - Reduced production costs at Montara reflecting the shut-in from August 2022 through the end of 2022; and
    - Lower Stag production costs due to reduced workover activities in 2022 compared to the previous year.
- In line with previous disclosures, adjusted annualised unit operating costs[2] for 2022 were US$37.49/boe, compared to US$26.22/bbl in 2021, primarily due to the lower production from Montara and the non-operated PenMal Assets;
- Adjusted EBITDAX increased by 14% to US$161.9 million compared to US$142.2 million in 2021, predominately due to higher oil prices driving higher revenues party offset by lower adjustments for one-off expenditures;
- Net profit after tax of US$8.5 million (2021: US$17.1 million loss after tax);
- Operating cash flow generation in 2022 of US$158.1 million, before movements in working capital, up 73% compared to 2021 of US$91.2 million;
- Capital expenditure of US$82.9 million (2021: US$56.0 million), a 48% increase from 2021, primarily due to the Stag infill

[1] Restatements explained in Note 45 of the Financial Statements

drilling programme completed in 2022 and the Akatara gas development at the Lemang PSC. The administration expenses related to the Lemang PSC are accounted for as operating expenditures (as Administrative Staff Costs and Other Expenses) of approximately US$2.0 million in 2022;
- Cash balances of US$123.3 million at 2022-year end, 5% higher compared to 2021 at US$117.9 million.
- The share buyback programme acquired 18.2 million shares in 2022, at an average cost of US$0.88 (0.76 GBp) per share for a total cost of US$16.2 million; and
- On 20 September 2022, the Directors declared a 2022 interim dividend of 0.65 US cents/share, equivalent to a total distribution of US$3.0 million. In line with the approach taken in respect of the final 2021 dividend in June 2022, a recommendation on the final dividend for 2022 will be made when the Group's audited accounts are released in late-May 2023.

Business development

- On 6 June 2022, the Group took the final investment decision to develop the Akatara gas field, onshore Indonesia, with project completion and first gas scheduled in the first half of 2024;
- On 27 October 2022, the Group announced the termination of the Maari acquisition due to a lack of progress on regulatory approvals and resultant uncertainty over the timing for the transfer of interest and operatorship;
- On 28 July 2022, the Group executed a sale and purchase agreement with BP Developments Australia Pty Ltd ("BP") to acquire BP's non-operated 16.67% working interest in the CWLH oil field development, offshore Western Australia; and
- On 24 November 2021, the Group executed a settlement and transfer agreement with PT Hexindo Gemilang Jaya ("Hexindo") to acquire the remaining 10% interest in the Lemang PSC.

Significant and subsequent events

- On 7 February 2022, the Bunga Kertas FPSO, deployed at the non-operated PenMal Assets, had its class suspended, resulting in operations being shut-in and production suspended. Jadestone has assumed operatorship of the non-operated licences following the decision of the previous operator to withdraw. Jadestone looks forward to evaluating redevelopment options for the fields;
- On 17 June 2022, the Montara FPSO released between three to five cubic metres of crude oil to sea during a routine oil transfer between storage tanks. As a precaution, production was shut in and the relevant authorities were notified. Following a temporary repair and isolation of the tank where the leak originated, production restarted while a permanent repair was developed. On 12 August 2022, an additional defect was identified in a ballast water tank, after which the Group took the decision to shut in production and prioritise permanent repairs. In response to the new defect, the regulator issued a General Direction requiring an independent assessment of the storage tanks before restarting production. Following the submission of the independent review of the Group's remediation plans and operational readiness for the Montara Venture FPSO on 8 February 2023, the local regulator lifted the General Direction on 27 February 2023 and Montara production resumed on 21 March 2023;
- On 19 January 2023, the Group executed a sale and purchase agreement with Salamander Energy (S.E. Asia) Limited (the "Seller"), an affiliate of PT Medco Energi Internasional Tbk to acquire the Seller's interest in three legal entities, which collectively own a 9.52% non-operated interest in the producing Sinphuhorm gas field and a 27.2% interest in the Dong Mun gas discovery onshore northeast Thailand; and
- On 17 February 2023, the Group closed a US$50.0 million debt facility ("Interim Facility") with two international banks. The closing of the Interim Facility forms part of the previously announced plan to arrange a reserves-based lending facility ("RBL"), which is a key element of the Group's medium-term financing strategy to fund development capital at the Indonesian Akatara Gas Project and enable further inorganic growth of the Group. US$28.5 million of the Interim Facility was drawn to fund the acquisition of a 9.52% interest in the Sinphuhorm gas field, with Group cash balances of US$63.9 million as at 31 March 2023. The Group continues to make good progress on the RBL workstreams, with one international bank credit approved and three others in the credit approval process, with signing of the RBL facility agreement targeted for May 2023. Once signed, the RBL is expected to close shortly thereafter once all customary conditions precedent are satisfied. It is expected that approval from the National Offshore Petroleum Titles Administrator ("NOPTA") of the transfer of titles relating to the acquisition for the CWLH fields interest will be required prior to drawing down the RBL.

2023 Guidance

- Production for the first three months of 2023 averaged just over 10,000 boe/d, reflecting tank repair and scheduled maintenance activities at Montara. Production for the nine months ending 31 December 2023 is expected to average 13,500-17,000 boe/d;
- Underlying operating costs in 2023 are expected to total US$180.0-210.0 million. When adjusted for a full-year of operating costs associated with the CWLH Assets acquisition, higher tanker costs at Stag and higher logistics costs at Montara in 2023, underlying operating costs are expected to be c.6% higher year-on-year, demonstrating cost control in an inflationary environment; and
- Capital expenditure guidance for 2023 is expected to total US$110.0-140.0 million, the largest investment programme in the Group's history. This is allocated primarily to the Akatara gas development project (c.70%), which is progressing well and remains on budget and schedule for first gas in H1 2024. A further 15% will be spent on the PM323 PSC infill drilling campaign offshore Malaysia.

[1] Realised oil price represents the actual selling price inclusive of premiums.
[2] Operating costs per boe, adjusted EBITDAX and net cash are non-IFRS measures and are explained in further detail on the Non-IFRS Measures section in this document.

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Conference call and webcast

The Company will host an investor and analyst conference call at 9:00 a.m. (London), 4:00 p.m. (Singapore) on Tuesday, 25 April 2023, including a question and answer session.

A live webcast of the presentation will be available at the link below. Dial-in details are also provided below. Please register approximately 15 minutes prior to the start of the call.

Webcast link: https://app.webinar.net/ZOKNWg2PypR
Event title: Jadestone Energy Full-Year 2022 Results
Time: 9:00 a.m. (UK time) / 4:00 p.m. (Singapore time)
Date: 25 April 2023
Conference ID: 61840872

To join the conference call by phone, please use the following link to register and be connected into the conference call automatically:

https://emportal.ink/3Z9UDjQ

Participants can also join the call via an operator through the numbers below.

Country	Dial-In Numbers
United Kingdom	08006522435
Australia	1800076068
Malaysia	1800817426
Indonesia	0078030208221
Singapore	18001013217
North America	888-390-0546

ENVIRONMENT, SOCIAL AND GOVERNANCE ("ESG")

As a responsible upstream operator, Jadestone contributes to an orderly energy transition by helping to meet regional Asia-Pacific energy demand whilst minimising the environmental footprint of its operations and committing to climate mitigation targets. In doing so, Jadestone aims to bring positive social and economic benefits for its stakeholders, local communities and people associated with its operations.

Jadestone believes that its strategy of acquiring and maximising the life of mid-life producing fields and the development of existing gas discoveries is consistent with the key findings of the IEA's Net Zero by 2050 Roadmap, stating that "there is no need for investment in new fossil fuel supply in the (IEA's) net zero pathway". The Group is well positioned to play its role in the energy transition as a responsible steward of mid-life assets divested by larger companies, committed to upholding climate targets as it continues to execute its Net Zero by 2040 strategy.

HSE performance

The Group's priority remains the health and safety of its staff, contractors and communities in which we operate, along with ensuring that any negative environmental impacts from operations are minimised.

Health and safety performance improved in 2022 with the total recordable injury frequency rate (TRIFR) at 2.86, working over 1.7 million work hours. There were four recordable injuries in 2022, with all individuals returning to work the same day. There was one lost time injury, incurred at Stag, from which the individual made a full recovery. A detailed investigation was completed and ensuing actions and engineering modifications fully implemented to prevent a reoccurrence.

Overall, the Group has had no major events resulting in significant environmental impact.

At the Akatara gas development within the Lemang PSC in Indonesia, work commenced to prepare the site for construction of the gas plant following final investment decision in June 2022. Jadestone has worked with the EPCI contractor to ensure that robust HSE management practices are implemented and monitored. The project worked consumed 0.6 million manhours in 2022 without a recordable injury. This represents an excellent performance as various ongoing work included high-risk activities such as pile driving, earth moving and general construction works. Visits to site are performed by Jadestone and the EPCI contractor's management teams on a monthly basis, a key focus area being HSE performance and regular monitoring through conducting site walk downs.

As referenced previously, on 18 June 2022, between three to five cubic metres of crude oil was released to sea during a routine oil transfer between tanks on the Montara Venture FPSO in Australia. The leak was successfully stopped within ten minutes and the Australian offshore energy regulator, NOPSEMA, was notified. The released oil had naturally dispersed in full by the morning of 19 June 2022. NOPSEMA subsequently issued a Prohibition Notice on 20 June 2022 requiring Jadestone to assess the fitness for service of all tanks capable of holding petroleum and undertake any appropriate remediation works prior to loading into that tank.

Production operations resumed in July 2022 but were then shut in again in August 2022 after an additional defect was identified in a ballast water tank in the Montara Venture FPSO. NOPSEMA issued a General Direction to Jadestone on 12 September 2022 requiring an independent third-party undertake a management system gap analysis, review and provide advice on remediation plans developed by Jadestone, and confirm operational readiness of the facility before restart could commence. This work was subsequently completed. The General Direction was lifted on 8 February 2023, followed by a restart programme that commenced on 23 March 2023.

GHG emissions and Net Zero commitment

In 2022, direct Scope 1 and 2 GHG emissions, which include the Malaysia operated assets following the PenMal Assets acquisition in 2021, amounted to 488,951 tonnes CO_2-e. When compared to full year 2021 Scope 1 and 2 GHG emissions (including the period before completion of the PenMal Assets acquisition), the Group's absolute direct Scope 1 and 2 GHG emissions were c.25% lower in 2022, largely due to the suspension of Montara operations discussed above.

In June 2022, the Group pledged to achieve Net Zero Scope 1 and 2 GHG emissions from its operated assets by no later than 2040. The detail of this commitment can be viewed on Jadestone's website[1].

Jadestone has partnered with a reputable third-party to:

- Establish its GHG accounting and target-setting methodology in alignment with best practice
- Develop a GHG business-as-usual forecast for the operated assets
- Identify, review and prioritise potential GHG reduction options for operated assets by establishing marginal abatement cost curves

The Group has made steady progress on defining its Net Zero roadmap, which will be completed by the end of 2023. It will disclose more details about the ongoing work in the 2022 Sustainability Report, to be published alongside the Jadestone's 2022 Annual Report in May 2023. The Group is committed to transparency by reporting at least annually on the progress made in implementing its Net Zero roadmap.

Illustrative of its efforts to minimise Scope 1 and 2 GHG emissions from its operations, a solar photovoltaic installation was piloted at the Akatara gas field development in Indonesia in April 2022, replacing diesel generators at four well pads. Solar power now fully meets well pad lighting and electricity needs, with potentially broader application within the Akatara development, such as the accommodation camp. In collaboration with other operators in the area, Jadestone is also participating in the planting of over 27,000 mangrove trees to positively impact the local communities and environment.

Governance

Jadestone's sustainability framework is founded on its commitment to upholding high standards of governance and responsible, social and ethical behaviour. Jadestone takes a strategic approach to embedding sustainability throughout its business that is overseen by the Board and supporting subcommittees.

On 7 April 2022, the Group announced the appointment of Jenifer Thien as an independent non-executive director. She brings knowledge and experience in environmental, social and governance ("ESG") strategy and joined the Remuneration, Governance and Nomination, and Health, Safety, Environment and Climate (HSEC) committees.

On 29 April 2022, Daniel Young stepped down from his role as the Chief Financial Officer ("CFO") and Executive Director and left the Group. Michael Horn took the role of interim CFO until 22 August 2022, when Bert-Jaap Dijkstra was appointed by the Board as CFO and Executive Director.

In 2022, the Group partnered with a specialist consultancy to update its corporate business ethics and compliance policies and further strengthen its alignment with best practice. In addition, a Human Rights Policy, Climate Policy and External Grievance Procedure were approved by the Board and can be viewed on Jadestone's website.

Following the discovery of defects within the Montara Venture FPSO tanks which led to the field being shut in and recognising the importance of the asset, both in terms of production and its safety and integrity, Jadestone's Board established a technical committee in September 2022. This action was taken in order to provide additional support and challenge to management during the Montara Venture FPSO hull and tank remediation work. The technical committee received weekly progress updates and reports, and direct feedback from senior operational staff on a monthly basis. The technical committee remains in place and will be dissolved following a satisfactory review of a third-party assessment of a 90-day period from restart in mid-March 2023.

OPERATIONAL REVIEW

Producing Assets

Australia

Montara Project

The Montara Project, in production licences AC/L7 and AC/L8, is located 254 km offshore Western Australia, in water depth of approximately 77 metres. The Montara Project comprises three separate fields being Montara, Skua and Swift/Swallow, which are produced through an owned FPSO, the Montara Venture.

As at 31 December 2022, the Montara assets had proven plus probable reserves of 18.5mmbbls (31 December 2021: 20.9mmbbls), 100% net to Jadestone.

The fields produce light sweet crude (42° API, 0.067% mass sulphur), which typically sells for average Dated Brent plus the average Tapis differential in the month of lifting. The premium in 2022 ranged between US$3.53/bbl to US$6.19/bbl, with an average premium of US$4.70/bbl.

Since acquiring a 100% interest in the Montara Project, the Group has invested over US$250.0 million in the field, incorporating significant amounts on repair and refurbishment of the Montara Venture, including corrosion management. However, reduced offshore manning levels and limited inter-state travel resulting from the COVID-19 pandemic slowed the pace of cargo tank inspection and repair activity onboard the Montara Venture in 2020 and 2021.

In June 2022, during routine production and crude oil cargo operations onboard the Montara Venture, approximately three to five cubic metres of oil was released to sea from a small hole in the bottom of cargo tank 2C, which while still in class, had seen a delay to its scheduled maintenance activity due to the COVID-19 impact referred to above. A temporary repair was effected in order to remove the remaining oil from tank 2C and key stakeholders, including the Australia offshore regulator NOPSEMA, were notified. Production was safely reinstated in early July 2022, although was shut in again in August after a further defect in ballast water tank 4S, was detected. At this point, the Group took the decision to shut-in production at Montara to prioritise tank inspection and repairs.

In September 2022, NOPSEMA issued a General Direction to the Company, which required Jadestone to engage an independent reviewer to undertake a gap recognition review, and assure the Group's remediation plans and operational readiness prior to the restart of production operations at Montara. DNV, the world's leading maritime classification society and an independent expert in risk management and assurance, was subsequently engaged as the independent reviewer and a report submitted to NOPSEMA in January 2023. NOPSEMA's review of the independent report was subsequently concluded and the General Direction lifted in February 2023. The Group's policies and procedures relating to FPSO tank inspection and repair and corrosion management have been strengthened as a result of this process.

Following successful completion of tank inspection and repair activities, as well as scheduled four-yearly maintenance activities, a phased production restart campaign commenced in March 2023. Initially, the Montara H6 well and Skua-10 and 11 wells were brought online in different configurations, with average production of 4,700 bbls/d over a 19 day period while works continued to commission the gas compression system on the FPSO, including specialist welding repairs to a reboiler.

There was a controlled four day production shutdown of the Montara Project in April 2023 as a precautionary measure due to the impact of Cyclone Ilsa. The facility was successfully remanned and production recommenced on 13 April from the Montara H6 well and Skua-11 well, with production since the cyclone shutdown subsequently averaging c.5,000 bbls/d, and the Skua-10 well was subsequently brought onstream.

Oil is currently being produced into oil tank 5C, with oil tank 6C due to be returned to service shortly, with the remaining oil tanks due to come back online sequentially following planned detailed inspection and any required repairs. To provide operational flexibility during this period, an offtake tanker has been contracted for three months and will be stationed nearby the Montara Venture until sufficient oil storage capacity is available. This is expected to result in a one-off cost of c.US$8.0 million in 2023.

Due to the impact of the Cyclone Ilsa related shutdown, the Company now expects that the Montara Venture gas compression will be brought back onstream at the end of April 2023, which would allow further wells to become available for production.

Absent any unplanned downtime, but including eight days of scheduled downtime in October 2023 for a compressor service and assuming well and subsurface performance in line with expectations, the Company expects Montara production to average approximately 6,000 bbls/d between April and December 2023. Montara Project oil production will become constrained by increasing gas production from Montara field reservoir until the installation of further compression on the Montara Venture, which remains in the planning phase.

Montara production averaged 4,227 bbls/d in 2022 (2021: 7,647 bbls/d), with the difference, in part, due to declines but more materially due to the production shut-in described above. Prior to the shut-in, production during H1 2022 was 7,509 bbls/d compared to 7,269 bbls/d in H1 2021.

There were five liftings in 2022, resulting in total sales of 1.7 mmbbls of crude oil compared to 3.0 mmbbls from six liftings in 2021.

Stag oilfield

The Stag oilfield, in production licence WA-15-L, is located 60 km offshore Western Australia in a water depth of approximately 47 metres.

As at 31 December 2022, the field contained total proved plus probable reserves of 12.1mmbbls (31 December 2021: 12.6mmbbls), 100% net to Jadestone.

The Stag oilfield produces heavy sweet crude (18^{o} API, 0.14% mass sulphur), which historically sells at a premium to Dated Brent. The premium in 2022 ranged between US$21.88/bbl to US$23.72/bbl with an average premium of US$ 22.78/bbl. The most recent lifting in February 2023 was agreed at a premium of US$19.10/bbl.

Production was 2,176 bbls/d in 2022 compared to 2,359 bbls/d in 2021. This decrease was predominately the result of a May 2022 shut down to perform planned pressure vessel inspections, which occur every three years.

During H2 2022, the Stag-50H and 51H infill wells were successfully drilled, completed and brought online in November 2022, generating additional production of approximately 600 bbls/d during December 2022.

There were four liftings in 2022 for total sales of 0.8 mmbbls, compared to 1.0 mmbbls in 2021 from the same number of liftings.

North West Shelf Project

The Cossack, Wanaea, Lambert and Hermes oil fields (the “North West Shelf Project” or “CWLH Assets”) are located 115km offshore Western Australia in production licences WA-3-L, WA-9-L, WA-11-L and WA-16-L situated in a water depth of approximately 80 metres.

On 28 July 2022, the Group executed a sale and purchase agreement (“SPA”) with BP Developments Australia Pty Ltd to acquire BP’s non-operated 16.67% working interest in the CWLH Assets for a total initial headline cash consideration of US$20.0 million, and certain subsequent contingent and decommissioning payments. The acquisition completed on 1 November 2022, following the satisfaction of all conditions precedent. The Group is currently applying to the National Offshore Petroleum Titles Administrator for approval of the dealing and registration on the petroleum titles relating to the acquired interest. This is expected soon.

As at 31 December 2022, the CWLH Assets contained total proved plus probable reserves of 5.1mmbbls, net to Jadestone.

The economic effective date of the acquisition was 1 January 2020, meaning that the Group was entitled to the net cash generated since the economic effective date to completion. As a result, the Group obtained a net cash receipt of US$7.0 million. Under the SPA and just prior to closing, the Group paid US$41.0 million in cash into a decommissioning trust fund held and managed by the operator. The last two instalments of US$20.5 million each are scheduled to be paid upon OPGGS title transfer and then before 31 December 2023, respectively.

The average production since the completion date of 1 November 2022 was 2,290 bbls/d, net to Jadestone's working interest. On an annualised basis, this was equivalent to 383 bbls/d net to Jadestone in 2022.

Jadestone lifted one cargo following completion of the acquisition, resulting in sales of 0.7 mmbbls in 2022.

Malaysia

Operated: PM 323 and PM 329 PSCs & Non-operated: PM 318 and AAKBNLP PSCs

The PenMal Assets consist of four PSCs, two of which are operated by the Group. The two operated PSCs comprise a 70% interest in PM329, containing the East Piatu field, and a 60% interest in PM323, which contains the East Belumut, West Belumut and Chermingat fields. Both PSCs are located approximately 230km northeast of Terengganu in shallow water.

The two non-operated (operated by others, or "OBO") PSCs consist of 50% working interests in each of PM318 PSC and the Abu, Abu Kecil, Bubu, North Lukut, and Penara oilfields (the "AAKBNLP") PSC. The two non-operated PSCs are located in the same region as PM329 and PM323.

As at 31 December 2022, the PenMal Assets contained total proved plus probable reserves of 8.9mmboe (2022: 11.2mmboe), net to Jadestone.

The PenMal Assets produce light sweet crude that is blended to Tapis grade (43^{o} API, 0.04% mass sulphur). The premium in 2022 ranged between US$0.96/bbl to US$14.41/bbl with an average premium realised of US$6.38/bbl. The most recent lifting in April 2023 was agreed at a premium of US$4.68/bbl.

In 2022, average production from the PenMal Assets was 3,884 bbls/d of oil and 4,908 mscf/d of gas, or 4,702 boe/d, net to Jadestone's working interest. In 2021, the average production after taking ownership in August 2021 was 5,377 bbls/d of oil and 4,084 mscf/d of gas, or 6,057 boe/d. The decrease of 1,355boe/d was the result of the non-operated licences PM318 and AAKBNLP being shut-in from February 2022 due to the class suspension of the FPSO which serves the non-operated PSCs.

Jadestone has assumed operatorship of the non-operated licences following the decision of the previous operator to withdraw. Jadestone believes there are significant remaining reserves on the licences and looks forward to evaluating redevelopment options for the fields.

There were 13 liftings from the PenMal Assets in 2022, resulting in total oil sales of 0.8 mmboe and total gas sales of 1.8 mmscf, compared to total oil sales of 0.6 mmboe and total gas sales of 0.6 mmscf in 2021 achieved between the date of acquisition up to 2021 year-end.

Pre-production Assets

Indonesia

Lemang PSC

The Lemang PSC is located onshore Sumatra, Indonesia. The PSC contains the Akatara field, which has been substantially de-risked with 11 wells drilled into the structure, plus three years of oil production history, up until the field ceased oil production in December 2019. Jadestone is redeveloping Akatara to supply gas, condensate and LPGs for local and regional use.

The Akatara gas field has been independently estimated to contain 2P gross reserves (pre local government back-in rights) of 71.1 bcf of sales gas, 2.2 mmbbls of condensate and 8.4 mmboe of LPG, equating to a combined 22.5 mmboe of resource. Following completion of the Hexindo acquisition (see below) Jadestone currently has a 100% interest in the Lemang PSC, with the local government retaining a 10% back-in right, which is expected to be exercised prior to first gas.

On 1 December 2021, a gas sales agreement was signed between Jadestone and PT Pelayanan Listrik Nasional Batam, as buyer.

On 6 June 2022, the Group announced that a final investment decision had been taken on the Akatara field development following the necessary approvals by the Indonesian upstream regulator. The Group awarded the engineering, procurement, construction and installation contract on 3 June 2022 and development activities commenced. As at 7 April 2023, the Akatara development project is approximately 28.3% completed and first gas remains on schedule for the first half of 2024.

On 23 November 2022, the Group completed the acquisition of the remaining 10% interest in the Lemang PSC. The 10% interest was acquired through the execution of a Settlement and Transfer Agreement between the Group and PT Hexindo Gemilang Jaya ("Hexindo"). In return for the transfer of Hexindo's 10% stake, the Group paid a cash consideration of US$0.5 million and released Hexindo from previously unpaid amounts relating to Hexindo's interest in the Lemang PSC.

Vietnam

Block 51 and Block 46/07 PSCs

Jadestone holds a 100% operated working interest in the Block 46/07 and Block 51 PSCs, both in shallow water in the Malay Basin, offshore southwest Vietnam.

The two contiguous blocks hold three discoveries: the Nam Du gas field in Block 46/07 and the U Minh and Tho Chu gas/condensate fields in Block 51, with aggregate 2C contingent resources of 93.9 mmboe.

The Tho Chu discovery in Block 51 is currently under a suspended development area status. A request for an extension to the Tho Chu suspended development area status has been submitted to the industry regulator and is expected to be granted in due course.

Jadestone continues to negotiate with the proposed buyer of gas from its offshore discoveries, aiming to sign a Heads of Agreement in the near-term for gas sales from the Nam Du/U Minh development. Following a gas sales agreement, the Group would work to finalise the field development plan and submit this for approval, a key step towards commercialising this significant and strategic resource in Jadestone's licences. Development of this resource would lessen Vietnam's future dependence on expensive LNG imports and would contribute towards the country's energy transition and stated goal of Net Zero greenhouse gas emissions by 2050.

Reserves and resources

Total 2P Reserves (net, mmboe)

	Australia	Malaysia[2]	Indonesia[2]	Total Group
Opening balance, 1 January 2022	**33.5**	**11.2**	**-**	**44.7**
Acquisitions	5.1	-	**-**	**5.1**
Transfer from 2C resources	-	-	16.8	**16.8**
Technical revisions	(0.5)	(0.6)	3.5	**2.4**
Production	(2.5)	(1.7)	-	**(4.2)**
Ending balance, 31 December 2022	**35.6**	**8.9**	**20.3**	**64.8**

As at 31 December 2022, the Group had proved plus probable oil reserves ("2P Reserves") of 64.8 mmboe, a 45% increase compared with year-end-2021 and a near six-fold replacement of production in the year. The primary drivers of the significant increase in reserves were the reclassification of 2C Contingent Resources from the Akatara gas field development in Indonesia to 2P Reserves following a final investment decision in June 2022, as well as the acquisition of the 16.67% interest in the producing CWLH fields offshore Australia, which completed in November 2022. Jadestone completed the acquisition of an interest in the Sinphuhorm gas field onshore Thailand, adding a further 4.1 mmboe of 2P Reserves, after the period end and therefore not included in 2022.

Total 2C Contingent Resources[3] (net, mmboe)

	Australia	Malaysia	Indonesia[2]	Vietnam[2]	Total Group
Opening balance, 1 January 2022	**-**	**-**	**16.8**	**93.9**	**110.7**
Acquisitions	-	-	**-**	**-**	0
Transfer to 2P reserves	-	-	(16.8)	**-**	(16.8)
Technical revisions	6.5	-	3.9	-	10.4
Ending balance, 31 December 2022	**6.5**	**-**	**3.9**	**93.9**	**104.3**

The Group's best case contingent resources ("2C resources") decreased slightly from 110.7 mmboe in 2021 to 104.3 mmboe in 2022. The reclassification of the Akatara gas development contingent resources to 2P reserves was partially offset by the inclusion of the Group's share of contingent resources associated with the potential life extension of, and infill drilling on, the CWLH Assets, as well as additional Akatara upside potential identified in excess of the volumes covered under the gas sales agreement.

[1] Proven and Probable Reserves for Jadestone's assets have been prepared in accordance with the June 2018 SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Resources Management System ("PRMS") as the standard for classification and reporting.

[2] Assumes oil equivalent conversion factor of 6,000 scf/boe.

[3] Contingent Resources based on ERCE estimates as at 31 December 2022, except for Vietnam 2C resources which are based on ERCE Competent Person's Report effective 31 December 2017.

FINANCIAL REVIEW

The following table provides select financial information of the Group, which was derived from, and should be read in conjunction with, the preliminary unaudited consolidated financial statements for the year ended 31 December 2022.

USD'000 except where indicated	2022	2021 (Restated)
Sales volume, barrels of oil equivalent (boe)	4,326,770	4,664,397
Production, boe/d	11,487	12,545
Realised oil price per barrel of oil equivalent (US$/boe)[1]	103.85	74.34
Realised gas price per million standard cubic feet (US$/mmscf)	1.63	1.61
Revenue	421,602	340,194
Production costs	(250,700)	(211,896)
Operating costs per barrel of oil equivalent (US$/boe)[2]	37.49	26.22
Adjusted EBITDAX[2]	161,929	142,242
Unit depletion, depreciation & amortisation (US$/boe)	10.80	13.67
Impairment of assets	(13,534)	-
Profit/(Loss) before tax	62,540	(4,293)
Profit/(Loss) after tax	8,522	(17,073)
Earnings/(Loss) per ordinary share: basic & diluted (US$)	0.02	(0.04)
Operating cash flows before movement in working capital	158,148	91,249
Capital expenditure	82,876	55,996
Net cash[2]	123,329	117,865

Benchmark commodity price and realised price

The average Brent price incorporated into the Group's liftings was US$101.32/bbl in 2022, an increase of 43% compared to the US$70.91/bbl achieved in 2021

The actual average realised price in 2022 increased in line with the benchmark price, by 40% to US$103.85/bbl, compared to US$74.34/bbl in 2021. The average realised premium for the year was US$7.81/bbl, compared to US$3.39/bbl in 2021. All producing assets saw an increase in premium, with Stag averaging US$22.78/bbl (2021:11.20/bbl), Montara US$4.70/bbl (2021: US$1.14/bbl) and PenMal operated assets US$6.67/boe (2021: US$1.62/boe).

The premiums have subsequently reduced from their peak in Q3 2022 with the most recent liftings in 2023 achieving a premium of US$19.10/bbl at Stag and US$4.68/bbl at the PenMal Assets.

Production and liftings

The Group produced an average of 11,487 boe/d in 2022, compared to 12,545 boe/d in 2021. Production decreased predominately due to the shut-in of Montara from mid-August 2022 to mid-March 2023.

Montara production declined 45% to 4,227 bbl/d in 2022 from 7,647 bbl/d in 2021 due to the shut-in of production from mid-August 2022 to mid-March 2023 following a management decision to suspend operations to focus on FPSO hull and tank repairs. Stag production in 2022 was 2,176 bbl/d, a decrease from 2021 of 2,359 bbls/d predominately due to a once-in-every-three-year routine shutdown. Lower production at Stag and Montara was partly offset by a full year of production from the PenMal Assets of 4,702 boe/d in 2022 compared to 2,539 boe/d in 2021, and the acquisition of the CWLH Assets contributing an annualised production of 383 bbls/d. The production rate from the CWLH Assets since acquisition on 1 November 2022 was 2,290 bbl/d.

[1] Realised oil price represents the actual selling price inclusive of premiums.
[2] Operating cost per boe, adjusted EBITDAX and net cash are non-IFRS measures and are explained in further detail on the Non-IFRS Measures section in this document.

The Group had 22 liftings during the year (2021: 17), mainly due to a full year of production and liftings from the PenMal Assets in 2022 compared to 2021 when the assets were owned for part of the year. Total Group's sales of 4.3 mmboe in 2022 included lifted volumes of 0.7 mmbbls from the CWLH Assets, a decrease compared to 4.7 mmboe in 2021 due to the lower production at Montara and the non-operated PenMal Assets.

Revenue

The Group generated revenue of US$421.6 million in 2022, an increase of 24% compared to 2021 of US$340.2 million. This represents the highest revenue ever recorded by the Group. The increase of US$81.4 million was predominately due to:

- Higher average realised prices in 2022, compared to 2021, contributing an additional US$150.8 million;
- A reduction in lifted volumes year-on-year resulting in decreased revenue of US$128.2 million (excluding price effects);
- The acquisition of the CWLH Assets in November 2022, which contributed US$56.6 million; and
- PenMal Assets generating higher gas revenue of US$2.1 million compared to US$1.0 million in 2021.

Production costs

Production costs increased by 30% in 2022 to US$250.7 million, from US$211.9 million in 2021, predominately due to:

- The acquisition of the CWLH Assets in November 2022 incurred production costs of US$37.7 million. This production cost is impacted by the accounting treatment of underlift at acquisition. This underlift of 315kbbls was recorded at fair value of US$27.3 million based on the market oil price of US$86.68/bbl. Please refer to Note 5 of the Group's consolidated financial statements for further details. The actual production cost per barrel was US$20.58/bbl, being the actual cash cost since the acquisition on 1 November 2022;
- Full year operations at the PenMal Assets, compared to five months in 2021, caused an increase in production costs by US$31.8 million which included a full year of supplementary payments with an increase of US$16.3 million, as a result of realised prices exceeded the PSC escalated base price;
- Production costs of Montara decreased by US$18.9 million reflecting the higher-than-normal workover costs at Skua 10/11 in 2021, partly offset by higher repairs & maintenance and logistics costs in 2022. The total repairs & maintenance costs directly associated with the FPSO hull and tank repairs was US$3.8 million; and
- Stag production costs decreased by US$11.8 million year-on-year predominately due to a decrease in workover activities in 2022.

Unit operating costs per barrel of oil equivalent were US$37.49/boe (2021: US$26.22/boe), before workovers and movement in inventories, but including net lease payments and certain other adjustments (see Non-IFRS measures section below in this document). The increase in unit costs reflects the reduction in production at Montara and non-operated PenMal Assets.

Depletion, depreciation and amortisation ("DD&A")

DD&A charges were US$61.8 million during the year, compared to US$80.2 million in 2021, predominately due to the lower production at Montara, resulting in a decrease of US$20.2 million. The reduction was partly offset by additional depletion charges at the CWLH Assets of US$1.7 million, since the date of acquisition of 1 November 2022.

Depreciation of the Group's right-of-use assets increased to US$13.0 million in 2022 from US$11.2 million in 2021, primarily due to the extension of a two-year lease for airport services to replace an expired lease.

The depletion cost on a unit basis was US$10.80/boe in 2022 (2021: US$13.67/boe), due to the lower depletion per unit of production at the PenMal Assets. The unit depletion cost in 2022 for the PenMal Assets was US$1.76/boe compared to US$3.87/boe in 2021. This was due to the absence of production from the non-operated PSCs which incurs a higher unit depletion rate.

The combined depletion cost per unit at both Stag and Montara increased to US$17.35/bbl from US$16.16/bbl in 2021 for the capital expenditures spent in 2021. The CWLH Assets recorded a unit depletion cost of US$12.36/bbl.

Staff costs

Total staff costs in 2022 were US$55.3 million, comprising US$26.1 million (2021: US$26.8 million) in relation to offshore employees, recorded under production costs, and US$29.2 million (2021: US$25.1 million) for office-based employees. The average number of employees during the year was 369 (2021: 278), with the additional staff costs and headcount year-on-year predominately associated with the PenMal Assets following completion of the acquisition in August 2021.

Other expenses

Other expenses decreased in 2022 to US$22.3 million (2021: US$26.2 million). The variance of US$3.9 million was predominately due to:

- Reduction of non-recurring costs by US$3.6 million compared to 2021. In 2022, the Group incurred non-recurring costs of US$1.6 million, relating to the acquisition of CWLH Assets, business development and various other one-off projects. In comparison, the Group incurred total non-recurring costs of US$5.2 million in 2021, which included internal reorganisation costs of US$1.1 million, acquisition costs of US$0.8 million associated with the PenMal Assets, and several other business development related expenses of US$3.3 million;
- The 2021 costs included a fair value loss on commodity swaps of US$4.6 million related to hedge contracts. The Group had no hedging in 2022;
- Assets written off reduced US$4.9 million to US$0.2 million in 2022 due to the prior year impairment of exploration assets.
- Net foreign exchange loss of US$0.4 million in 2022 (2021: US$1.0 million);
- Additional contingent payments related to the future Dated Brent prices and Saudi CP prices associated with the Lemang PSC of US$7.3 million were recognised in 2022; and
- Higher provisions for slow-moving materials and spares on hand in 2022 of US$3.8 million (2021: US$2.6 million).

Other income

Other income of US$28.0 million was generated during 2022 compared to US$7.7 million in 2021, due to:

- Insurance claim receipts of US$18.0 million compensating for loss of production at Montara related to drilling activities at Skua 10/11 in 2021;
- Rebate income of US$5.0 million (2021: US$4.5 million) arose from the sublease of right-of-use assets under the Group's helicopter lease contract; and
- Net foreign exchange gains of US$0.5 million (2021: US$2.5 million).

Impairment

In 2021, the Group recorded an impairment of US$13.5 million associated with the oil and gas properties of the non-operated PenMal Assets, following the decision by the operator to shut-in production after the FPSO class suspension in February 2022. The impairment of US$13.5 million comprised US$6.9 million of oil and gas properties written off and US$6.6 million associated with the 2022 year end revaluation of decommissioning estimates embedded in the ARO provision.

As at 31 December 2022, the fields were shut-in and management does not expect to restart production in 2023 while the Group is exploring strategic alternatives, including a potential redevelopment of the non-operated PenMal Assets.

Taxation

The tax charge of US$54.0 million in 2022 (2021: US$12.8 million) which includes a current tax charge of US$27.1 million (2021: US$7.3 million) and a deferred tax charge of US$26.9 million (2021: US$5.4 million).

The tax paid during the year included US$18.5 million of corporate tax payments and Australian petroleum resource rent tax ("PRRT") tax refund of US$1.1 million in Australia, plus US$15.7 million of PITA tax in Malaysia.

The weighted average effective tax rate based on profit jurisdictions was 56% (2021: 49%). The consolidated group effective tax rate is 86% (2021: -198%) as loss making jurisdictions negatively impact profit before tax. The profit before tax from Australia and Malaysia was US$87.6 million (2021: US$15.3 million), which was impacted by corporate, development and exploration losses of US$25.0 million (2021; US$19.6 million). The corporate tax losses are not recognised as deferred tax as there is not sufficient certainty that taxable income will be realised in the future.

USD'000	2022	2021 (Restated)
Profit before tax	62,540	(4,293)
Expected effective tax rate	56%	49%
Tax at the country level effective rate	**35,022**	**(2,103)**
Effect of different tax rates in loss making jurisdictions	13,934	11,167
Malaysia PITA tax losses on non-operated PSCs	8,742	6,298
Utilisation of PRRT credits	(21,661)	(2,845)
PRRT tax refunded	(1,121)	(1,374)
Capital gain tax from acquisition of CWLH Assets	1,486	-
Australian decommissioning levy	336	196
Non-deductible expenses	938	3,226
Deferred tax permanent differences	9,645	(3,176)
PRRT permanent differences	7,032	3,371
Adjustment in respect to prior years	(335)	(1,980)
Tax charge for the year	**54,018**	**12,780**

Australia Taxes

The Australian corporate income tax rate is 30% and PRRT is 40% which is cash based and income tax deductible. The combined standard effective tax rate is 58%, the actual effective tax rate of 46% is lower predominately due to the utilisation of PRRT credits brought forward at Montara. Montara has approximately US$3.5 billion of unutilised PRRT credits and is not expected to incur any PRRT expense over the economic life of the asset.

Malaysia Taxes

Malaysian petroleum income tax ("PITA") is a PSC based tax on petroleum operations at the rate of 38%. There are no other material taxes in Malaysia. The Group incurred losses from the non-operated PSCs (PM318 / AAKBNLP) as a result of ceasing production in February 2022, which resulted a tax non-deductible impairment of $13.5 million. There has been a significant increase in deferred tax permanent taxable difference which predominately relate to changes in the ARO estimates at year end which won't be tax deductible at the end of the field life when the Group commences decommissioning activities due to insufficient estimated taxable income.

2022 RECONCILIATION OF NET CASH

	US$'000	US$'000
Cash and cash equivalents, 31 December 2021		**117,865**
Revenue	421,602	
Other operating income	26,485	
Production costs	(250,700)	
Staff costs	(28,247)	
General and administrative expenses	(10,992)	
Operating cash flows before movements in working capital		**158,148**
Movement in working capital		37,219*
Net tax paid		(33,130)
Purchases of intangible exploration assets, oil and gas properties, and plant and equipment[1]		(82,628)
Cash received from acquisition of CWLH Assets		5,750
Placement of decommissioning trust fund for CWLH Assets		(41,000)*
Cash paid for acquisition of 10% interest of Lemang PSC		(500)
Other investing activities		881
Shares repurchased		(16,070)
Dividends paid		(9,216)
Repayment of lease liabilities		(13,914)
Other financing activities		(76)
Total cash and cash equivalent, 31 December 2022		**123,329**

The movement in working capital and the placement of decommissioning trust fund for CWLH Assets are combined in the consolidated statement of cash flows for the year ended 31 December 2022 under the movements in working capital.

NON-IFRS MEASURES

The Group uses certain performance measures that are not specifically defined under IFRS, or other generally accepted accounting principles. These non-IFRS measures comprise operating cost per barrel of oil equivalent (opex/boe), adjusted EBITDAX, outstanding debt, and net cash.

The following notes describe why the Group has selected these non-IFRS measures.

[1] Total capital expenditure was US$82.9 million (2021: US$56.0 million), comprising total capital expenditure paid of US$82.6 million (2021:

US$55.9 million), plus accrued capital expenditure of US$0.3 million (2021: US$0.1 million).

Operating costs per barrel of oil equivalent (Opex/boe)

Opex/boe is a non-IFRS measure used to monitor the Group's operating cost efficiency, as it measures operating costs to extract hydrocarbons from the Group's producing reservoirs on a unit basis.

Opex/boe is defined as total production costs excluding oil inventories movement and underlift/overlift, write down of inventories, workovers (to facilitate better comparability period to period) and non-recurring repair and maintenance. It includes lease payments related to operational activities, net of any income earned from right-of-use assets involved in production, and excludes transportation costs, PenMal Asset supplementary payments, DD&A and short-term COVID-19 subsidies.

The adjusted production cost is then divided by total produced barrels of oil equivalent for the prevailing period to determine the unit operating cost per barrel of oil equivalent.

USD'000 except where indicated	**2022**	**2021**
Production costs (reported)	250,700	211,896
Adjustments		
Lease payments related to operating activity[1]	13,687	10,619
Underlift, overlift and crude inventories movement[2]	(39,436)	(15,053)
Workover costs[3]	(10,190)	(67,006)
Other income[4]	(5,030)	(4,512)
Non-recurring repair and maintenance[5]	(13,761)	(6,593)
Transportation costs	(8,341)	(1,231)
PenMal Assets supplementary payments and Australian royalties[6]	(26,381)	(8,255)
PenMal non-operated assets FPSO rectification costs[7]	(4,056)	
Australian Government JobKeeper scheme	-	196
Adjusted production costs	**157,192**	**120,061**
Total production (barrels of oil equivalent)	4,192,618	4,578,962
Operating costs per barrel of oil equivalent	**37.49**	**26.22**

[1] Lease payments related to operating activities are lease payments considered to be operating costs in nature, including leased helicopters for transporting offshore crews. These lease payments are added back to reflect the true cost of production.

[2] Underlift, overlift and crude inventories movement are added back to the calculation to match the full cost of production with the associated production volumes (i.e., numerator to match denominator).

[3] Workover costs are excluded to enhance comparability. The frequency of workovers can vary significantly, across periods.

[4] Other income represents the rental income from a helicopter rental contract (a right-of-use asset) to a third party.

[5] Non-recurring repair and maintenance costs in 2022 predominately related to Montara Skua-11 repair works, gas compressor solar engine change out and tank repairs following the shut-in of Montara in August 2022.

[6] The supplementary payments are required under the terms of PSCs based on Jadestone's profit oil after entitlements between the government and joint venture partners. The Australian royalties were related to local decommissioning cost recovery levy plus royalties payable to the local state government arose from the acquisition of the CWLH Assets.

[7] PenMal non-operated assets FPSO rectification costs refer to the costs incurred to repair the FPSO BUK CLASS at PM318 and AAKBNLP PSCs following its suspension in February 2022.

Adjusted EBITDAX

Adjusted EBITDAX is a non-IFRS measure which does not have a standardised meaning prescribed by IFRS. This non-IFRS measure is included because management uses the information to analyse cash generation and financial performance of the Group.

Adjusted EBITDAX is defined as profit from continuing activities before income tax, finance costs, interest income, DD&A, other financial gains, non-recurring expenses and exploration assets write-offs.

The calculation of adjusted EBITDAX is as follow:

USD'000	2022	2021 (Restated)
Revenue	421,602	340,194
Production cost	(250,700)	(211,896)
Administrative staff costs	(29,218)	(25,068)
Impairment of assets	(13,534)	-
Other expenses	(22,305)	(26,181)
Other income, excluding interest income	27,152	7,602
Other financial gains	1,904	266
Unadjusted EBITDAX	**134,901**	**84,917**
Non-recurring		
Net loss from oil price derivatives	-	4,633
Impairment of assets	13,534	-
Non-recurring opex[1]	20,534	53,096
Intangible exploration assets written off	-	5,260
Insurance claim receipts[2]	(17,977)	(10,333)
Change in provision – Lemang PSC contingent payments	7,333	-
Fair value loss on contingent considerations	1,920	438
Others[3]	1,684	4,231
	27,028	**57,325**
Adjusted EBITDAX	**161,929**	**142,242**

[1] Includes one-off major maintenance/well intervention activities, in particular the Montara Skua-11 repair works, gas compressor solar engine change out and storage tank repairs after the Montara production shut-in since mid-August 2022.

[2] Represents insurance claim received at Montara for the compensation for the loss of production relating to drilling activities at the two Skua field wells in 2020. The 2021 insurance claim receipt was received at Montara and related to the well control claim for the Skua 11 well workovers.

[3] Includes business development costs, external funding sourcing costs, Maari transition team costs and internal reorganisation costs.

Debt

As at 31 December 2022, the Group had no outstanding borrowings.

As part of its previously announced plan to arrange a RBL, on 17 February 2023, the Group entered into a US$50.0 million Interim Facility with two international banks. The Interim Facility has a term of nine months and carries an initial margin of 450 basis points over SOFR, which steps up in the event repayment occurs more than three months after closing. Subsequently, US$28.5 million of the Interim Facility was drawn principally to fund the acquisition of a 9.52% interest in the Sinphuhorm gas field in February 2023, with the remaining US$21.5 million solely being available to fund the next US$20.5 million instalment of the CWLH abandonment trust funding and related Interim Facility expenses.

The Group continues to make good progress on the RBL workstreams, with one international bank credit approved and three others in the credit approval process, with signing of the RBL facility agreement targeted for May 2023. Once signed, the RBL is expected to close shortly thereafter once all customary conditions precedent are satisfied. It is expected that approval from NOPTA of the transfer of titles relating to the acquisition for the CWLH fields interest will be required prior to drawing down the RBL.

The Group is finalising the final phase of its corporate restructuring which commenced with the previously announced internal reorganisation in 2021. Creating a subsidiary holding the Group's producing assets to facilitate the RBL is an element of this. Currently, the final entity transfers are pending regulatory approval by NOPTA for transfer of the Australian entities, and whilst the transfer of the Malaysian operations has been approved by PETRONAS (the Malaysian regulator) effective 1 April 2023, the parties are finalising related contract novations to reflect PETRONAS' given approval. The NOPTA approval for the transfer of the Australian entities and the relevant contract novations in respect of transfer of the Malaysian operations are expected in May 2023. The finalisation of the internal restructuring is not expected to hold up the closing of the RBL.

Once closed and the conditions precedent satisfied, the Group intends to draw down the RBL to fund planned 2023 activity, particularly at the Akatara gas development as well as enabling further acquisitions.

The Directors have a high degree of confidence that the RBL facility agreement will be entered into by late May 2023. In the event that it is not, a third-party non-dilutive offer of funding has been received, which in combination with the Interim Facility, would provide sufficient liquidity to protect key capital and operating expenditures.

As is normal, the Group expects to hedge a proportion of its future production as part of its commitments under the RBL. This is currently expected to take the form of a rolling hedge programme, commencing with an initial hedge for 40% of lifted oil volumes between Q4 2023 and Q3 2024 (inclusive). Additional hedges on a forward rolling basis will be based on management's outlook, with a minimum of 20% of oil volumes to meet commitments under the RBL.

Net cash

Net cash is a non-IFRS measure which does not have a standardised meaning prescribed by IFRS. Management uses this measure to analyse the financial strength of the Group. This measure is used to ensure capital is managed effectively in order to support ongoing operations, and to raise additional funds, if required.

USD'000	2022	2021
Cash and cash equivalents, representing net cash of the Group	**123,329**	**117,865**

Net cash is defined as the sum of cash and cash equivalents and restricted cash, less outstanding borrowings, of which there were none at 31 December 2022.

Consolidated Statement of Profit or Loss and Other Comprehensive Income for the year ended 31 December 2022

	Notes	2022 USD'000	2021 Restated* USD'000
Continuing operations			
Revenue	4 & 40	421,602	340,194
Production costs	5	(250,700)	(211,896)
Depletion, depreciation and amortisation	6	(61,834)	(80,215)
Administrative staff costs	7	(29,218)	(25,068)
Other expenses	10	(22,305)	(26,181)
Impairment of assets	12	(13,534)	-
Other income	13	28,033	7,682
Finance costs	14	(11,408)	(9,075)
Other financial gains	15	1,904	266
Profit/(Loss) before tax		**62,540**	**(4,293)**
Income tax expense	16	(54,018)	(12,780)
Profit/(Loss) for the year		**8,522**	**(17,073)**
Profit/(Loss) per ordinary share			
Basic and diluted (US$)	18	0.02	(0.04)
Profit/(Loss) for the year, representing total comprehensive income for the year		**8,522**	**(17,073)**

*Certain 2021 comparative information has been restated. Please refer to Note 45.

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

Consolidated Statement of Financial Position as at 31 December 2022

	Notes	2022 USD'000	2021 Restated* USD'000
Assets			
Non-current assets			
Intangible exploration assets	21	77,928	93,241
Oil and gas properties	22	456,768	353,592
Plant and equipment	23	7,318	8,963
Right-of-use assets	24	8,193	13,852
Other receivables and prepayment	28	90,590	48,500
Deferred tax assets	26	9,118	26,389
Cash and cash equivalents	29	676	852
Total non-current assets		**650,591**	**545,389**
Current assets			
Inventories	27	18,911	23,299
Trade and other receivables	28	20,368	32,578
Tax recoverable	16	9,725	9,367
Cash and cash equivalents	29	122,653	117,013
Total current assets		**171,657**	**182,257**
Total assets		**822,248**	**727,646**
Equity and liabilities			
Equity			
Capital and reserves			
Share capital	30	339	358
Share premium	30	983	201
Merger reserve	32	146,270	146,270
Share-based payments reserve	33	26,907	25,936
Capital redemption reserve	34	21	-
Accumulated losses		(51,787)	(35,023)
Total equity		**122,733**	**137,742**
Non-current liabilities			
Provisions	35	508,539	410,697
Lease liabilities	36	2,880	4,504
Deferred tax liabilities	26	88,406	66,166
Total non-current liabilities		**599,825**	**481,367**

	Notes	2022 USD'000	2021 Restated* USD'000
Current liabilities			
Lease liabilities	36	6,227	11,161
Trade and other payables	38	73,752	70,107
Provisions	35	703	930
Tax liabilities		19,008	26,339
Total current liabilities		**99,690**	**108,537**
Total liabilities		**699,515**	**589,904**
Total equity and liabilities		**822,248**	**727,646**

*Certain 2021 comparative information has been restated and reclassified between line items. Please refer to Note 45.

Consolidated Statement of Changes in Equity for the year ended 31 December 2022

	Share capital USD'000	Share premium USD'000	Merger reserve USD'000	Share-based payments reserve USD'000	Capital redemption reserves USD'000	Accumulated losses USD'000	Total USD'000
As at 1 January 2021	466,979	-	-	24,985	-	(331,322)	160,642
Loss for the year, representing total comprehensive income for the year	-	-	-	-	-	(17,073)	(17,073)
Capital reduction (Note 30)	(467,387)	-	146,270	-	-	321,117	-
Dividend paid (Note 31)	-	-	-	-	-	(7,745)	(7,745)
Share-based payments (Note 8)	-	-	-	951	-	-	951
Shares issued (Note 30)	766	201	-	-	-	-	967
Total transactions with owners, recognised directly in equity	**(466,621)**	**201**	**146,270**	**951**	**-**	**313,372**	**(5,827)**
As at 31 December 2021 (Restated)*	**358**	**201**	**146,270**	**25,936**	**-**	**(35,023)**	**137,742**
Profit for the year, representing total comprehensive income for the year	-	-	-	-	-	8,522	8,522
Dividend paid (Note 31)	-	-	-	-	-	(9,216)	(9,216)
Share-based payments (Note 8)	-	-	-	971	-	-	971
Shares issued (Note 30)	2	782	-	-	-	-	784
Share repurchases (Note 30)	(21)	-	-	-	21	(16,070)	(16,070)
Total transactions with owners, recognised directly in equity	**(19)**	**782**	-	**971**	**21**	**(25,286)**	**(23,531)**
As at 31 December 2022	**339**	**983**	**146,270**	**26,907**	**21**	**(51,787)**	**122,733**

*Certain 2021 comparative information has been restated. Please refer to Note 45.

Consolidated Statement of Cash Flows for the year ended 31 December 2022

	Notes	2022 USD'000	2021 Restated* USD'000
Operating activities			
Profit/(Loss) before tax		62,540	(4,293)
Adjustments for:			
Depletion, depreciation and amortisation	6	61,834	80,215
Finance costs	14	11,408	9,075
Impairment of oil and gas properties	12	13,534	-
Change in provision	10	7,333	-
Allowance for slow moving inventories	10	3,768	2,624
Share-based payments	7	971	951
Assets written off	10	212	5,332
Unrealised foreign exchange loss/(gain)	13	245	(1,838)
Accretion income on Australian tax repayment plan	15	(1,904)	-
Income recognised for previously unrecognised amount due from joint arrangement partner	13	(912)	-
Interest income	13	(881)	(80)
Reversal of loss on oil derivatives	10	-	(471)
Accretion income on non-current VAT receivables	15	-	(266)
Operating cash flows before movements in working capital		**158,148**	**91,249**
Increase in trade and other receivables		(214)	(6,602)
(Increase)/Decrease in inventories		(1,096)	9,152
(Decrease)/Increase in trade and other payables		(2,471)	21,631
Cash generated from operations		**154,367**	**115,430**
Net tax paid		(33,130)	(11,834)
Net cash generated from operating activities		**121,237**	**103,596**
Investing activities			
Cash received from acquisition of CWLH Assets	18	5,750	-
Cash paid for acquisition of 10% interest of Lemang PSC	19	(500)	-
Cash received from acquisition of Peninsular Malaysia assets	20	-	29,252
Cash paid for acquisition of Peninsular Malaysia assets	20	-	(20,033)
Payment for oil and gas properties	22	(78,938)	(51,380)
Payment for plant and equipment	23	(356)	(682)
Payment for intangible exploration assets	21	(3,334)	(3,858)
Transfer from debt service reserve account	29	-	8,445
Interest received	13	881	80
Net cash used in investing activities		**(76,497)**	**(38,176)**

	Notes	2022 USD'000	2021 USD'000
Financing activities			
Proceeds from issuance of shares	30	784	967
Shares repurchased	30	(16,070)	-
Dividends paid	31	(9,216)	(7,745)
Repayment of borrowings	37	-	(7,296)
Repayment of lease liabilities	37	(13,914)	(12,972)
Interest on lease liabilities paid	37	(769)	(1,222)
Interest on borrowings paid	37	-	(209)
Interest paid		(91)	(74)
Net cash used in financing activities		**(39,276)**	**(28,551)**
Net increase in cash and cash equivalents		**5,464**	**36,869**
Cash and cash equivalents at beginning of the year		117,865	80,996
Cash and cash equivalents at end of the year	29	**123,329**	**117,865**

*Certain 2021 comparative information has been restated and reclassified between line items. Please refer to Note 45.

Notes to the Consolidated Financial Statements for the year ended 31 December 2022

1. CORPORATE INFORMATION

Jadestone Energy plc (the "Company" or "Jadestone") is an oil and gas company incorporated in the United Kingdom and registered in England and Wales. The Company's registration number is 13152520. The Company is the ultimate parent company of all Jadestone subsidiaries (the "Group"). These consolidated financial statements have been prepared for the Jadestone Energy Group and reflect the full financial year ended 31 December 2022 in respect of the ultimate parent company in accordance with IFRS (see Note 2).

The Company's shares are traded on AIM under the symbol "JSE".

The financial statements are expressed in United States Dollars ("US$" or "USD").

The Group is engaged in production, development, exploration and appraisal activities in Australia, Malaysia, Vietnam, Indonesia and Thailand. The Group's producing assets are in the Vulcan (Montara) basin, Carnarvon (Stag) basin and Cossack, Wanaea, Lambert, and Hermes oil fields, located in offshore of Western Australia, the East Piatu, East Belumut, West Belumut and Chermingat fields, located in shallow water in offshore Peninsular Malaysia and the Khorat (Sinphuhorm) basin onshore Thailand.

The Company's head office is located at 3 Anson Road, #13-01 Springleaf Tower, Singapore 079909. The registered office of the Company is Suite 1, 7th Floor, 50 Broadway, London, United Kingdom SW1H OBL.

2. SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PREPARATION

The financial statements have been prepared in accordance with UK-adopted International Accounting Standards and International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and in conformity with the requirements of the Companies Act 2006 (the "Act").

The financial statements have been prepared on the historical cost convention basis, except as disclosed in the accounting policies below. Historical cost is generally based on the fair value of the consideration given in exchange for goods and services.

Fair value is the price that would be received from selling an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, regardless of whether that price is directly observable or estimated using another valuation technique. In estimating the fair value of an asset or a liability, the Group takes into account the characteristics of the asset or liability which market participants would take into account when pricing the asset or liability at the measurement date. Fair value for measurement and/or disclosure purposes in these consolidated financial statements is determined on such a basis, except for share-based payment transactions that are within the scope of IFRS 2 *Share-based Payment*, leasing transactions that are within the scope of IFRS 16 *Leases*, and measurements that have some similarities to fair value but are not fair value, such as net realisable value in IAS 2 *Inventories*, or value in use in IAS 36 *Impairment of Assets*.

In addition, for financial reporting purposes, fair value adjustments are categorised into level 1, 2 or 3, based on the degree to which the inputs to the fair value adjustments are observable and the significance of the inputs to the fair value measurement in its entirety, which are described as follows:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Group can access at the measurement date;

- Level 2 inputs are inputs, other than quoted prices included within Level 1, that are observable for the asset or liability, either directly or indirectly; and

- Level 3 inputs are unobservable inputs for the asset or liability.

GOING CONCERN

The Directors are required to consider the availability of resources to meet the Group's liabilities for the foreseeable future.

In 2022, the Group generated US$ 121.2 million of cash flow from operating activities and incurred a total of US$115.8 million from investing and financing activities, reflecting an increase in net cash of US$ 5.5 million to arrive at the year-end cash and cash equivalents of US$ 123.3 million.

Post 2022 year end up to 31 March 2023, the Group kept its cash balance between US$60.0 and 90.0 million. During this period, the Group continued to generate cash from two liftings (342,373 barrels), with an average realised price of US$97.33/bbl. Trade related expenditure, most notably payables from the Stag drilling programme, was settled. The Group made two contingent payments for a total of US$5.0 million, relating to the acquisition of the Peninsular Malaysia assets (the "PenMal Assets") and the CWLH Assets (Notes 20 and 18). Separately, the Group paid US$27.8 million for the acquisition of interest in Sinphuhorm gas field in February 2023 and received US$28.5 million of cash from the new debt facility secured by the Group in February 2023 (Note 43).

The Group regularly monitors its cash, funding and liquidity position. Near term cash projections are revised and underlying assumptions reviewed, generally monthly, and longer-term projections are also updated regularly. Downside price, which could be potentially impacted by the transition to a lower carbon economy, plus other risking scenarios are considered, such as potential delay in the development of Indonesian Akatara Gas Project, unfavourable foreign exchanges and higher than expected inflation rates. In addition to commodity sales prices, the Group is also potentially exposed to potential production interruptions such as weather downtime and planned and unplanned shutdowns for workovers and repair and maintenance activities.

The Group continues to make good progress on the RBL workstreams, with one international bank credit approved and three others in the credit approval process, with signing of the RBL facility agreement targeted for May 2023. Once signed, the RBL is expected to close shortly thereafter once all customary conditions precedent are satisfied. It is expected that approval from NOPTA of the transfer of titles relating to the acquisition for the CWLH fields interest will be required prior to drawing down the RBL.

The Directors have a high degree of confidence that the RBL facility agreement will be entered into by late May 2023. In the event that it is not, a third-party non-dilutive offer of funding has been received, which in combination with the Interim Facility, would provide sufficient liquidity to protect key capital and operating expenditures.

All these factors have been considered in the Group's near and longer term cash projections. For the purposes of the Group's going concern assessment, we have reviewed cash projections for the period from 1 April 2023 to 31 December 2024, the 'going concern period'.

Having taken into consideration the above factors, the Directors have reasonable expectation that the Group has adequate resources to continue in operational existence for the going concern period. Accordingly, they adopted the going concern basis in preparing these financial statements.

Adoption of new and revised standards
New and amended IFRS standards that are effective for the current year

In the current year, the Group adopted the following amendment that is effective from the beginning of the year and is relevant to its operations. The adoption of this amendment has not resulted in changes to the Group's accounting policies.

Amendments to IAS 16	Property, Plant and Equipment – Proceeds before Intended Use
Amendments to IFRS 3	Reference to Conceptual Framework
Amendments to IAS 37	Onerous Contracts – Cost of Fulfilling a Contract
Amendments to IFRSs	Annual Improvements to IFRS Standards 2018 – 2020

New and revised IFRSs in issue but not yet effective

At the date of authorisation of these financial statements, the Group has not applied the following amendments to IFRS standards relevant to the Group that have been issued but are not yet effective:

Amendments to IAS 1[1]	Classification of Liabilities as Current or Non-current – Deferral of Effective Date
Amendments to IAS 1[2]	Non-current Liabilities with Covenants
Amendments to IAS 1 and Practice Statement 2[1]	Making Materiality Judgements – Disclosure of Accounting Policies
Amendments to IAS 8[1]	Definition of Accounting Estimates
Amendments to IAS 12[1]	Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction
Amendments to IFRS 16[2]	Lease Liability in a Sale and Leaseback

For amendments that are effective from 1 January 2023, the Directors of the Group anticipate that the application of these amendments may have an impact on the Group's consolidated financial statements in future periods. For amendments that are effective from 1 January 2024, the Directors of the Group are currently performing an assessment of the impact of these amendments and anticipate that the application of these amendments may have an impact on the Group's consolidated financial statements in future periods should such transactions arise.

BASIS OF CONSOLIDATION

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

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

The Company reassesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control listed above.

Consolidation of a subsidiary begins when the Company obtains control over the subsidiary and ceases when the Company loses control of the subsidiary. Specifically, income and expenses of a subsidiary acquired or disposed of during the year are included in the consolidated statement of profit or loss and other comprehensive income from the date the Company gains control until the date when the Company ceases to control the subsidiary.

Profit or loss and each component of other comprehensive income are attributed to the owners of the Company. Total comprehensive income of subsidiaries is attributed to the owners of the Company and to the non-controlling interests, even if this results in the non-controlling interests having a deficit balance.

When necessary, adjustments are made to the financial statements of subsidiaries to bring their accounting policies into line with the Group's accounting policies.

All intragroup assets and liabilities, equity, income, expenses and cash flows relating to transactions between members of the Group are eliminated in full on consolidation.

[1] Effective from 1 January 2023.
[2] Effective from 1 January 2024.

BUSINESS COMBINATIONS

Acquisitions of businesses, including joint operations which are assessed to be businesses, are accounted for using the acquisition method. The consideration for each acquisition is measured as the aggregate of the acquisition date fair values of assets given, liabilities incurred by the Company to the former owners of the acquiree, and equity interests issued by the Company in exchange for control of the acquiree. Acquisition-related costs are recognised in profit or loss as incurred.

At the acquisition date, the identifiable assets acquired and the liabilities assumed are recognised at their fair value, except that:

- Deferred tax assets or liabilities, and liabilities or assets related to employee benefit arrangements are recognised and measured in accordance with IAS 12 *Income Taxes* and IAS 19 *Employee Benefits* respectively;

- Liabilities or equity instruments related to share-based payment transactions of the acquiree, or the replacement of an acquiree's share-based payment awards transactions with share-based payment awards transactions of the acquirer, in accordance with the method in IFRS 2 *Share-based Payment* at the acquisition date; and

- Assets, or disposal groups, that are classified as held for sale in accordance with IFRS 5 *Non-Current Assets Held for Sale and Discontinued Operations* are measured in accordance with that Standard.

Goodwill is measured as the excess of the sum of the consideration transferred, the amount of any non-controlling interests in the acquiree, and the fair value of the acquirer's previously held equity interest in the acquiree (if any) over the net of the acquisition-date amounts of the identifiable assets acquired and the liabilities assumed. If, after reassessment, the net of the acquisition-date amounts of the identifiable assets acquired and liabilities assumed exceeds the sum of the consideration transferred, the amount of any non-controlling interests in the acquiree and the fair value of the acquirer's previously held interest in the acquiree (if any), the excess is recognised immediately in profit or loss as a bargain purchase gain.

Where applicable, the consideration for the acquisition includes any asset or liability resulting from a contingent consideration arrangement, measured at its acquisition date fair value. Subsequent changes in such fair values are adjusted against the cost of acquisition where they qualify as measurement period adjustments. Measurement period adjustments are adjustments that arise from additional information obtained during the 'measurement period' (which cannot exceed one year from the acquisition date) about facts and circumstances that existed at the acquisition date. The subsequent accounting for changes in the fair value of the contingent consideration, that do not qualify as measurement period adjustments, depends on how the contingent consideration is classified.

Contingent consideration that is classified as equity is not re-measured at subsequent reporting dates and its subsequent settlement is accounted for within equity. Contingent consideration that is classified as a liability is remeasured at subsequent reporting dates with the corresponding gain or loss being recognised in profit or loss.

If the initial accounting for a business combination is incomplete by the end of the reporting period in which the combination occurs, the Group reports provisional amounts for the items for which the accounting is incomplete. Those provisional amounts are adjusted during the measurement period (see below), or additional assets or liabilities are recognised, to reflect new information obtained about facts and circumstances that existed as of the acquisition date that, if known, would have affected the amounts recognised as at that date.

The measurement period is the period from the date of acquisition to the date the Group obtains complete information about facts and circumstances that existed as at the acquisition date and is subject to a maximum of one year from acquisition date.

Where an interest in a production sharing contract ("PSC") is acquired by way of a corporate acquisition, the interest in the PSC is treated as an asset purchase unless the acquisition of the corporate vehicle meets the definition of a business and the requirements to be treated as a business combination.

ACCOUNTING FOR TRANSACTION THAT IS NOT A BUSINESS COMBINATION

When a transaction or other event does not meet the definition of a business combination due to the asset or group of assets not meeting the definition of a business, it is termed an 'asset acquisition'. In such circumstances, the acquirer:

- Identifies and recognises the individual identifiable assets acquired (including those assets that meet the definition of, and recognition criteria for, intangible assets in IAS 38) and liabilities assumed; and
- Allocates the cost of acquiring the group of assets and liabilities to the individual identifiable assets and liabilities on the basis of their relative fair values at the date of purchase.

Such a transaction or event does not give rise to goodwill or a gain on a bargain purchase.

Transaction costs in an asset acquisition are generally capitalised as part of the cost of the assets acquired in accordance with applicable standards.

FOREIGN CURRENCY TRANSACTIONS

The Group's consolidated financial statements are presented in USD, which is the parent's functional currency and presentation currency. The functional currencies of subsidiaries are determined based on the economic environment in which they operate.

In preparing the financial statements of each individual Group entity, transactions in currencies other than the entity's functional currency are recorded at the rates of exchange prevailing on the dates of the transactions. At the end of each reporting period, monetary items denominated in foreign currencies are retranslated at the rates prevailing at the end of the reporting period. Non-monetary items carried at fair value that are denominated in foreign currencies are retranslated at the rates prevailing on the date when the fair value was determined. Non-monetary items that are measured in terms of historical cost in a foreign currency are not retranslated.

Exchange differences arising on the settlement of monetary items, and on retranslation of monetary items, are included in profit or loss for the period.

Exchange differences arising on the retranslation of non-monetary items carried at fair value are included in profit or loss for the period, except for differences arising on the retranslation of non-monetary items in respect of which gains or losses are recognised in other comprehensive income. For such non-monetary items, any exchange component of that gain or loss is also recognised in other comprehensive income. There is no foreign currency translation reserve created at the Group level as the functional currencies of all subsidiaries are denominated in USD.

JOINT OPERATIONS

A joint operation is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require unanimous consent of the parties sharing control.

When a Group entity undertakes its activities under joint operations, the Group as a joint operator recognises in relation to its interest in a joint operation:

- Its assets, including its share of any assets held jointly;
- Its liabilities, including its share of any liabilities incurred jointly;
- Its revenue from the sale of its share of the output arising from the joint operation; and

- Its expenses, including its share of any expenses incurred jointly.

The Group accounts for the assets, liabilities, revenue and expenses relating to its interest in a joint operation in accordance with the IFRS standards applicable to the particular assets, liabilities, revenues and expenses.

When a Group entity transacts with a joint operation in which a Group entity is a joint operator (such as a sale or contribution of assets), the Group is considered to be conducting the transaction with the other parties to the joint operation, and gains and losses resulting from the transactions are recognised in the Group's consolidated financial statements only to the extent of other parties' interests in the joint operation.

When a Group entity transacts with a joint operation in which a Group entity is a joint operator (such as a purchase of assets), the Group does not recognise its share of the gains and losses until it resells those assets to a third party.

Changes to the Group's interest in a PSC usually require the approval of the appropriate regulatory authority. A change in interest is recognised when:

- Approval is considered highly likely; and

- All affected parties are effectively operating under the revised arrangement.

Where this is not the case, no change in interest is recognised and any funds received or paid are included in the statement of financial position as contractual deposits.

EXPLORATION AND EVALUATION COSTS

The costs of exploring for and evaluating oil and gas properties, including the costs of acquiring rights to explore, geological and geophysical studies, exploratory drilling and directly related overheads such as directly attributable employee remuneration, materials, fuel used, rig costs and payments made to contractors are capitalised and classified as intangible exploration assets ("E&E assets").

If no potentially commercial hydrocarbons are discovered, the E&E assets are written off through profit or loss as a dry hole. If extractable hydrocarbons are found and, subject to further appraisal activity (e.g., the drilling of additional wells), it is probable that they can be commercially developed, the costs continue to be carried as intangible exploration costs, while sufficient/continued progress is made in assessing the commerciality of the hydrocarbons.

Costs directly associated with appraisal activity undertaken to determine the size, characteristics and commercial potential of a reservoir following the initial discovery of hydrocarbons, including the costs of appraisal wells where hydrocarbons were not found, are initially capitalised as E&E assets.

All such capitalised costs are subject to technical, commercial and management review, as well as review for indicators of impairment at the end of each reporting period. This is to confirm the continued intent to develop or otherwise extract value from the discovery. When such intent no longer exists, or if there is a change in circumstances signifying an adverse change in initial judgment, the costs are written off.

When commercial reserves of hydrocarbons are determined and development is approved by management, the relevant expenditure is transferred to oil and gas properties. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved or probable reserves are determined to exist. The determination of proved or probable reserves is dependent on reserve evaluations which are subject to significant judgments and estimates.

Costs related to geological and geophysical studies that relate to blocks that have not yet been acquired, and costs related to blocks for which no commercially viable hydrocarbons are expected, are taken direct to the profit or loss and have been disclosed as exploration expenses.

OIL AND GAS PROPERTIES

Producing assets

The Group recognises oil and gas properties at cost less accumulated depletion, depreciation and impairment losses. Directly attributable costs incurred for the drilling of development wells and for the construction of production facilities are capitalised, together with the discounted value of estimated future costs of decommissioning obligations. Workover expenses are recognised in profit or loss in the period in which they are incurred, unless it generates additional reserves or prolongs the economic life of the well, in which case it is capitalised. When components of oil and gas properties are replaced, disposed of, or no longer in use, they are derecognised.

Depletion and amortisation expense

Depletion of oil and gas properties is calculated using the units of production method for an asset or group of assets, from the date in which they are available for use. The costs of those assets are depleted based on proved and probable reserves.

Costs subject to depletion include expenditures to date, together with approved estimated future expenditure to be incurred in developing proved and probable reserves. Costs of major development projects are excluded from the costs subject to depletion until they are available for use.

The impact of changes in estimated reserves is dealt with prospectively by depleting the remaining carrying value of the asset over the remaining expected future production. If reserves estimates are revised downwards, earnings could be affected by higher depletion expense, or an immediate write-down of the property's carrying value.

Depletion amount calculated based on production during the year is adjusted based on the net movement of crude inventories at year end against beginning of the year, i.e., depletion cost for crudes produced but not lifted are capitalised as part of cost of inventories and recognised as depletion expense when lifting occurs.

Asset restoration obligations

The Group estimates the future removal and restoration costs of oil and gas production facilities, wells, pipelines and related assets at the time of installation or acquisition of the assets, and based on prevailing legal requirements and industry practice. In most instances, the removal of these assets will occur many years in the future. The estimates of future removal costs are made considering relevant legislation and industry practice and require management to make judgments regarding the removal date, the extent of restoration activities required, and future removal technologies.

Site restoration costs are capitalised within the cost of the associated assets, and the provision is stated in the statement of financial position at its total estimated present value. These costs are based on judgements and assumptions regarding removal dates, technologies, and industry practice. This estimate is evaluated on a periodic basis and any adjustment to the estimate is applied prospectively. Changes in the estimated liability resulting from revisions to estimated timing, amount of cash flows, or changes in the discount rate are recognised as a change in the asset restoration liability and related capitalised asset restoration cost within oil and gas properties.

The Malaysian and Indonesian regulators require upstream oil and gas companies to contribute to an abandonment cess fund, including making periodic cess payments, throughout the production life of the oil or gas field. The cess payment amount is assessed based on the estimated future decommissioning expenditures. For operated licences, the cess payment paid is classified as non-current receivables as the cess payment paid is reclaimable by the Group in the future following the commencement of decommissioning activities. For non-operated licences, the cess payment paid reduces the asset restoration liability.

An abandonment trust fund was set up as part of the acquisition of the CWLH Assets to ensure there are sufficient funds available for decommissioning activities at the end of field life. The payment paid into the trust fund is classified as non-current receivables as the amount is reclaimable by the Group in the future following the commencement of decommissioning activities.

The change in the net present value of future obligations, due to the passage of time, is expensed as an accretion expense within financing charges. Actual restoration obligations settled during the period reduce the decommissioning liability.

Capitalised asset restoration costs are depleted using the units of production method (see above accounting policy).

BORROWING COSTS

Borrowing costs are allocated to periods over the term of the related debt, at a constant rate on the carrying amount. Borrowings, as shown on the consolidated statement of financial position, are net of arrangement fees and issue costs, and the borrowing costs are amortised through to the statement of profit or loss and other comprehensive income as finance costs over the term of the debt.

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

All other borrowing costs are recognised in the profit or loss in the period in which they are incurred.

Investment income earned on the temporary investment of specific borrowings pending their expenditure on qualifying assets is deducted from the borrowing costs eligible for capitalisation. All other borrowing costs are recognised in the statement of profit or loss in the period in which they are incurred.

PLANT AND EQUIPMENT

Plant and equipment is stated at cost less accumulated depreciation and any recognised impairment loss.

Depreciation is charged so as to write off the cost of assets evenly over their estimated useful lives, on the following:

- Computer equipment: 3 years; and
- Fixtures and equipment: 3 years.

The estimated useful lives, residual values and depreciation method are reviewed at each year end, with the effect of any changes in estimate accounted for on a prospective basis.

Materials and spares which are not expected to be consumed within the next twelve months from the year end are classified as plant and equipment.

Right-of-use assets are depreciated over the shorter period of the lease term and the useful life of the underlying asset. If the ownership of the underlying asset in a lease is transferred, or the cost of the right-of-use asset reflects that the Group expects to exercise a purchase option, the related right-of-use asset is depreciated over the useful life of the underlying asset.

An item of plant and equipment is derecognised upon disposal or when no future economic benefits are expected to arise from the continued use of asset. Any gain or loss arising on the disposal or retirement of an item of plant and equipment is determined as the difference between the sales proceeds and the carrying amount of the asset and is recognised in profit or loss.

IMPAIRMENT OF OIL AND GAS PROPERTIES, PLANT AND EQUIPMENT, RIGHT-OF-USE ASSETS AND INTANGIBLE ASSETS EXCLUDING GOODWILL

At the end of each reporting period, the Group reviews the carrying amounts of its oil and gas properties, plant and equipment, right-of-use assets and intangible assets, excluding goodwill, to determine whether there is any indication that those assets have suffered an impairment loss. If any such indication exists, the recoverable amount of the asset is estimated in order to determine the extent of the impairment loss (if any). The impairment is determined on each individual cash-generating unit basis (i.e., individual oil or gas field or individual PSC). Where there is common infrastructure that is not possible to measure the cash flows separately for each oil or gas field or PSC, then the impairment is determined based on the aggregate of the relevant oil or gas fields or the combination of two or more PSCs. When a reasonable and consistent basis of allocation can be identified, corporate assets are also allocated to individual cash-generating units, or otherwise they are allocated to the smallest group of cash-generating units for which a reasonable and consistent allocation basis can be identified.

Recoverable amount is the higher of fair value less costs of disposal ("FVLCOD") and value in use. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which estimates of future cash flows have not been adjusted. FVLCOD will be assessed on a discounted cash flow basis where there is no readily available market price for the asset or where there are no recent market transactions. Assumptions relating to forecast capital expenditures that enhance the productive capacity can be included in the discounted cash flows model, but only to the extent that a typical market participant would take a consistent view. The post-tax discounted cash flows are compared against the carrying amount of the asset on an after-tax basis; that is, after deducting deferred tax liabilities relating to the asset or group of assets.

If the recoverable amount of an asset (or cash-generating unit) is estimated to be less than its carrying amount, the carrying amount of the asset (or cash-generating unit) is reduced to its recoverable amount. An impairment loss is recognised immediately in profit or loss.

Where an impairment loss subsequently reverses, the carrying amount of the asset (or cash-generating unit) is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognised for the asset (or cash-generating unit) in prior years. A reversal of an impairment loss is recognised immediately in profit or loss.

INVENTORIES

Inventories are valued at the lower of cost and net realisable value. Cost is determined as follows:

- Petroleum products, comprising primarily of extracted crude oil stored in tanks, pipeline systems and aboard vessels, and natural gas, are valued using weighted average costing, inclusive of depletion expense; and

- Materials, which include drilling and maintenance stocks, are valued at the weighted average cost of acquisition.

Net realisable value represents the estimated selling price in the ordinary course of business less the estimated costs of completion and the estimated costs necessary to make the sale. The Group uses its judgement to determine which costs are necessary to make the sale considering its specific facts and circumstances, including the nature of the inventories. If the carrying value exceeds net realisable value, a write-down is recognised. The write-down may be reversed in a subsequent period if the inventory is still on hand, but the circumstances which caused the write-down no longer to exist.

Provision for slow moving materials and spares are recognised in the "other expenses" (Note 10) line item in profit or loss as they are non-trade in nature.

FINANCIAL INSTRUMENTS

Financial assets and financial liabilities are recognised in the Group's consolidated statement of financial position when the Group becomes a party to the contractual provisions of the instrument.

Financial assets and financial liabilities are initially measured at fair value. Transaction costs that are directly attributable to the acquisition or issue of the financial assets and financial liabilities (other than financial assets and financial liabilities measured at fair value through the profit or loss) are added to or deducted from the fair value of the financial assets or financial liabilities, as appropriate, on initial recognition.

Transaction costs directly attributable to the acquisition of financial assets or financial liabilities measured at fair value through profit or loss are recognised immediately in profit or loss.

Financial assets

All financial assets are recognised and derecognised on a trade date basis, where the purchases or sales of financial assets is under a contract whose terms require delivery of assets within the time frame established by the market concerned.

All recognised financial assets are measured subsequently in their entirety, at either amortised cost or fair value, depending on the classification of the financial assets.

Classification of financial assets

Debt instruments that meet the following conditions are measured subsequently at amortised cost:

- The financial asset is held within a business model whose objective is to hold financial assets in order to collect contractual cash flows; and

- The contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

Debt instruments that meet the following conditions are subsequently measured at fair value through other comprehensive income ("FVTOCI"):

- The financial asset is held within a business model whose objective is achieved by both collecting contractual cash flows and selling the financial assets; and

- The contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

By default, all other financial assets are subsequently measured at fair value through profit or loss ("FVTPL").

Amortised cost and effective interest method

The effective interest method is a method of calculating the amortised cost of a financial asset and of allocating interest income over the relevant period.

For financial assets, the effective interest rate is the rate that exactly discounts estimated future cash receipts (including all fees paid or received that form an integral part of the effective interest rate, transaction costs and other premiums or discounts) excluding expected credit losses, through the expected life of the financial asset, or, where appropriate, a shorter period, to the gross carrying amount of the financial instrument on initial recognition.

The amortised cost of a financial asset is the amount at which the financial asset is measured at initial recognition minus the principal repayments, plus the cumulative amortisation using the effective interest method of any difference between that initial amount and the maturity amount, adjusted for any loss allowance. The gross carrying amount of a financial asset is the amortised cost of a financial asset before adjusting for any loss allowance.

Interest income is recognised using the effective interest method for financial assets measured subsequently at amortised cost and at fair value through other comprehensive income. For financial assets other than purchased or originated credit impaired financial assets, interest income is calculated by applying the effective interest rate to the gross carrying amount of a financial asset, except for financial assets that have subsequently become credit impaired. For financial assets that have subsequently become credit impaired, interest income is recognised by applying the effective interest rate to the amortised cost of the financial asset. If, in subsequent reporting periods, the credit risk on the credit impaired financial instrument improves so that the financial asset is no longer credit impaired, interest income is recognised by applying the effective interest rate to the gross carrying amount of the financial asset.

Interest income is recognised in profit or loss and is included in "other income" (Note 13) line item.

Impairment of financial assets

The Group's financial assets that are subject to the expected credit loss model comprise trade and other receivables. While cash and bank balances are also subject to the impairment requirements of IFRS 9 *Financial Instruments*, the expected credit loss allowances are not expected to be significant due to the banks have external credit ratings of 'investment grade' in accordance with the globally understood definition.

The Group's trade and other receivables are primarily with counterparties to oil and gas sales, joint arrangement partners and non-trade related parties.

The concentration of credit risk relates to the Group's single customer with respect to oil sales in Australia, and a different single customer for oil and gas sales in Malaysia. Both customers have an A2 credit rating (Moody's). All trade receivables are generally settled 30 days after the sale date. In the event that an invoice is issued on a provisional basis then the final reconciliation is paid within three days of the issuance of the final invoice, largely mitigating any credit risk.

The Group recognises lifetime expected credit loss ("ECL") for trade receivables. The expected credit losses on these financial assets are estimated based on days past due, applying expected non-recoveries for each group of receivables.

The Group measures the loss allowance for other receivables and amounts due from joint arrangement partners at an amount equal to 12 months ECL, as there is no significant increase in credit risk since initial recognition.

Significant increase in credit risk

In assessing whether the credit risk on a financial instrument has increased significantly since initial recognition, the Group compares the risk of a default occurring on the financial instrument as at the reporting date with the risk of a default occurring on the financial instrument as at the date of initial recognition. In making this assessment, the Group considers both quantitative and qualitative information that is reasonable and supportable, including historical experience and forward looking information that is available without undue cost or effort. Forward looking information considered includes the future prospects of the industries in which the Group's debtors operate, based on consideration of various external sources of actual and forecast economic information plus environment impacts that relate to the Group's core operations.

In particular, the following information is taken into account when assessing whether credit risk has increased significantly since initial recognition:

- An actual or expected significant deterioration in the financial instrument's external (if available), or internal credit rating;

- Significant deterioration in external market indicators of credit risk for a particular financial instrument, e.g., a significant increase in the credit spread, the credit default swap prices for the debtor, or the length of time or the extent to which the fair value of a financial asset has been less than its amortised cost;

- Existing or forecast adverse changes in business, financial or economic conditions that are expected to cause a significant decrease in the debtor's ability to meet its debt obligations;

- An actual or expected significant deterioration in the operating results of the debtor;

- Significant increases in credit risk on other financial instruments of the same debtor; and

- An actual or expected significant adverse change in the regulatory, economic, or technological environment of the debtor that results in a significant decrease in the debtor's ability to meet its debt obligations.

Despite the foregoing, the Group assumes that the credit risk on a financial instrument has not increased significantly since initial recognition if the financial instrument is determined to have low credit risk at the reporting date. A financial instrument is determined to have low credit risk if i) the financial instrument has a low risk of default, ii) the borrower has a strong capacity to meet its contractual cash flow obligations in the near term and iii) adverse changes in economic and business conditions in the longer term may, but will not necessarily, reduce the ability of the borrower to fulfil its contractual cash flow obligations.

The Group regularly monitors the effectiveness of the criteria used to identify whether there has been a significant increase in credit risk and revises them, as appropriate, to ensure that the criteria are capable of identifying a significant increase in credit risk before the amount becomes past due.

Definition of default

The Group considers the following as constituting an event of default, for internal credit risk management purposes, as historical experience indicates that receivables that meet either of the following criteria are generally not recoverable:

- When there is a breach of financial covenants by the counterparty; or

- Information developed internally or obtained from external sources indicates that the debtor is unlikely to pay its creditors, including the Group, in full (without taking into account any collateral held by the Group).

Credit-impaired financial assets

A financial asset is credit-impaired when one or more events that have a detrimental impact on the estimated future cash flows of that financial asset have occurred. Evidence that a financial asset is credit-impaired includes observable data about the following events:

- Significant financial difficulty of the issuer or the borrower;

- A breach of contract, such as a default or past due event;

- The lender(s) of the borrower, for economic or contractual reasons relating to the borrower's financial difficulty, having granted to the borrower a concession(s) that the lender(s) would not otherwise consider;

- It is becoming probable that the borrower will enter bankruptcy or other financial reorganisation; or

- The disappearance of an active market for that financial asset because of financial difficulties.

Write-off policy

The Group writes off a financial asset when there is information indicating that the counterparty is in severe financial difficulty and there is no realistic prospect of recovery, e.g., when the counterparty has been placed under liquidation or has entered into bankruptcy proceedings, or in the case of trade receivables, when the amounts are over one year past due, whichever occurs sooner. Financial assets written off may still be subject to enforcement activities under the Group's recovery procedures, taking into account legal advice where appropriate. Any recoveries made are recognised in profit or loss.

Measurement and recognition of expected credit losses

The measurement of ECL is a function of the probability of default, loss given default (i.e., the magnitude of the loss if there is a default), and the exposure at default. The assessment of the probability of default, and loss given default, is based on historical data adjusted by forward looking information as described above.

As for the exposure at default, for financial assets, this is represented by the assets' gross carrying amount at the reporting date, together with any additional amounts expected to be drawn down in the future by the default date determined based on historical trend, the Group's understanding of the specific future financing needs of the debtors, and other relevant forward looking information.

For financial assets, the expected credit loss is estimated as the difference between all contractual cash flows that are due to the Group in accordance with the contract, and all the cash flows that the Group expects to receive, discounted at the original effective interest rate.

If the Group has measured the loss allowance for a financial instrument at an amount equal to lifetime ECL in the previous reporting period, but determines at the current reporting date that the conditions for lifetime ECL are no longer met, the Group measures the loss allowance at an amount equal to 12 month ECL at the current reporting date, except for assets for which the simplified approach was used.

Derecognition of financial assets

The Group derecognises a financial asset only when the contractual rights to the cash flows from the asset expire, or when it transfers the financial asset and substantially all the risks and rewards of ownership of the asset to another entity. If the Group neither transfers nor retains substantially all the risks and rewards of ownership, and continues to control the transferred asset, the Group recognises its retained interest in the asset and an associated liability for amounts it may have to pay. If the Group retains substantially all of the risks and rewards of ownership of a transferred financial asset, the Group continues to recognise the financial asset and also recognises a collaterialised borrowing for the proceeds received.

On derecognition of a financial asset measured at amortised cost, the difference between the asset's carrying amount and the sum of the consideration received and receivables, is recognised in the profit or loss.

Financial liabilities

All financial liabilities are measured subsequently at amortised cost, using the effective interest method or at FVTPL.

However, financial liabilities that arise when a transfer of a financial asset does not qualify for derecognition, or when the continuing involvement approach applies, are measured in accordance with the specific accounting policies set out below.

Financial liabilities at FVTPL

Financial liabilities are classified as at FVTPL when the financial liability is (i) contingent consideration of an acquirer in a business combination, (ii) held for trading, or (iii) designated as at FVTPL.

A financial liability other than a contingent consideration of an acquirer in a business combination may be designated as at FVTPL upon initial recognition if:

- Such designation eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise; or

- The financial liability forms part of a group of financial assets or financial liabilities or both, which is managed and its performance is evaluated on a fair value basis, in accordance with the Group's documented risk management or investment strategy, and information about the grouping is provided internally on that basis; or

- It forms part of a contract containing one or more embedded derivatives, and IFRS 9 permits the entire combined contract to be designated as at FVTPL.

Financial liabilities classified as at FVTPL are measured at fair value, with any gains or losses arising on changes in fair value recognised in profit or loss to the extent that they are not part of a designated hedging relationship (see hedge accounting policy). The net gain or loss recognised in profit or loss incorporates any interest paid on the financial liability and is included in either "other financial gains" (Note 15) or "finance costs" (Note 14) line item in profit or loss.

Financial liabilities measured subsequently at amortised cost

Other financial liabilities are measured subsequently at amortised cost, using the effective interest method.

The effective interest method is a method of calculating the amortised cost of a financial liability and of allocating interest expense over the relevant period. The effective interest rate is the rate that exactly discounts estimated future cash payments (including all fees paid or received that form an integral part of the effective interest rate, transaction costs and other premiums or discounts) through the expected life of the financial liability, or (where appropriate) a shorter period, to the amortised cost of a financial liability.

Derecognition of financial liabilities

The Group derecognises financial liabilities when, and only when, the Group's obligations are discharged, cancelled or they expire. The difference between the carrying amount of the financial liability derecognised, and the consideration paid and payable, is recognised in profit or loss.

Equity instruments

Ordinary shares issued by the Company are classified as equity and recorded at the par value in the share capital account and the fair value of the proceeds received recorded in the share premium account.

FAIR VALUE ESTIMATION OF FINANCIAL ASSETS AND LIABILITIES

The fair value of current financial assets and liabilities carried at amortised cost, approximate their carrying amounts, as the effect of discounting is immaterial.

SHARE-BASED PAYMENTS

Share-based incentive arrangements are provided to employees, allowing them to acquire shares of the Company.

The fair value of equity-settled options granted is recognised as an employee expense, with a corresponding increase in equity.

Equity-settled share options are valued at the date of grant using the Black-Scholes pricing model, and are charged to operating costs over the vesting period of the award. The charge is modified to take account of options granted to employees who leave the Group during the vesting period and forfeit their rights to the share options. In the case of market-related performance conditions, the Group revises its estimates of the number of equity instruments expected to vest at the end of the reporting period. The impact of the revision of the original estimates, if any, is recognised in profit or loss such that the cumulative expense reflects the revised estimate, with a corresponding adjustment to the share options reserve.

Equity-settled share-based payment transactions with parties other than employees are measured at the fair value of goods or services received, except where that fair value cannot be estimated reliably, in which case they are measured at the fair value of the equity instruments granted, measured at the date at which the entity obtains the goods or the counterparty renders the service.

LEASES

The Group as lessee

The Group assesses whether a contract is or contains a lease, at inception of the contract. The Group recognises a right-of-use asset and a corresponding lease liability with respect to all lease arrangements in which it is the lessee, except for short-term leases (defined as leases with a lease term of 12 months or less) and leases of low value assets (such as personal computers, small items of office furniture and telephones). For these leases, the Group recognises the lease payments as an operating expense on a straight-line basis over the term of the lease, unless another systematic basis is more representative of the time pattern in which economic benefits from the leased assets are consumed.

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

Lease payments included in the measurement of the lease liability comprise fixed lease payments (including in substance fixed payments).

The lease liability is presented as a separate line in the consolidated statement of financial position.

The lease liability is subsequently measured by increasing the carrying amount to reflect interest on the lease liability (using the effective interest method), and by reducing the carrying amount to reflect the lease payments made.

The Group remeasures the lease liability (and makes a corresponding adjustment to the related right-of-use asset) whenever:

- The lease term has changed or there is a significant event or change in circumstances resulting in a change in the assessment of exercise of a purchase option, in which case the lease liability is remeasured by discounting the revised lease payments using a revised discount rate;

- The lease payments change due to changes in an index or rate or a change in expected payment under a guaranteed residual value, in which case the lease liability is remeasured by discounting the revised lease payments using an unchanged discount rate (unless the lease payments change is due to a change in a floating interest rate, in which case a revised discount rate is used); or

- A lease contract is modified and the lease modification is not accounted for as a separate lease, in which case the lease liability is remeasured based on the lease term of the modified lease by discounting the revised lease payments using a revised discount rate at the effective date of the modification.

During the year, the Group did not make any such adjustments.

The right-of-use assets comprise the initial measurement of the corresponding lease liability, lease payments made at or before the commencement day, less any lease incentives received and any initial direct costs. They are subsequently measured at cost less accumulated depreciation and impairment losses.

Whenever the Group incurs an obligation for costs to dismantle and remove a leased asset, restore the site on which it is located, or restore the underlying asset to the condition required by the terms and conditions of the lease, a provision is recognised and measured under IAS 37. To the extent that the costs relate to a right-of-use asset, the costs are included in the related right-of-use asset, unless those costs are incurred to produce inventories.

Right-of-use assets are depreciated over the shorter period of the lease term and the useful life of the underlying asset. If a lease transfers ownership of the underlying asset, or the cost of the right-of-use asset reflects that the Group expects to exercise a purchase option, the related right-of-use asset is depreciated over the useful life of the underlying asset. The depreciation starts at the commencement date of the lease.

Right-of-use assets are presented as a separate line in the consolidated statement of financial position.

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

As a practical expedient, IFRS 16 permits a lessee not to separate non-lease components, and instead account for any lease and associated non-lease components as a single arrangement. The Group has not used this practical expedient. For contracts that contain a lease component and one or more additional lease or non-lease components, the Group allocates the consideration in the contract to each lease component on the basis of the relative stand-alone price of the lease component and the aggregate standalone price of the non-lease components.

PROVISIONS

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

The amount recognised as a provision is the best estimate of the consideration required to settle the present obligation at the end of the reporting period, taking into account the risks and uncertainties surrounding the obligation. Where a provision is measured using the cash flows estimated to settle the present obligation, its carrying amount is the present value of those cash flows, and where the effect of the time value of money is material. The provisions held by the Group are asset restoration obligations, contingent payments, employee benefits and incentive scheme, as set out in Note 35.

RETIREMENT BENEFIT OBLIGATIONS

Payments to defined contribution retirement benefit plans are charged as an expense as and when employees have tendered the services entitling them to the contributions. Payments made to state managed retirement benefit schemes, such as Malaysia's Employees Provident Fund, are dealt with as payments to defined contribution plans where the Group's obligations under the plans are equivalent to those arising in a defined contribution retirement benefit plan. The Group does not have any defined benefit plans.

REVENUE

Revenue from contracts with customers is recognised in the profit or loss when performance obligations are considered met, which is when control of the hydrocarbons are transferred to the customer.

Revenue from the production of oil and gas, in which the Group has an interest with other producers, is recognised based on the Group's working interest and the terms of the relevant production sharing contracts.

Liquids production revenue is recognised when the Group gives up control of the unit of production at the delivery point agreed under the terms of the sale contract. This generally occurs when the product is physically transferred into a vessel, pipe or other delivery mechanism. The amount of production revenue recognised is based on the agreed transaction price and volumes delivered. In line with the aforementioned, revenue is recognised at a point in time when deliveries of the liquids are transferred to customers.

Gas production revenue is meter measured based on the hydrocarbon volumes delivered. The volumes delivered over a calendar month are invoiced based on monthly meter readings. The price is either fixed (gas) or linked to an agreed benchmark (high sulphur fuel oil) in advance. This methodology is considered appropriate as it is normal business practice under such arrangements. In line with the aforementioned, revenue is recognised at a point in time when deliveries of the gas are transferred to the customer.

A receivable is recognised once transfer has occurred, as this represents the point in time at which the right to consideration becomes unconditional, and only the passage of time is required before the payment is due.

Under/Overlift

Offtake arrangements for oil and gas produced in certain of the Group's jointly owned operations may result in the Group not receiving and selling its precise share of the overall production in a period. The resulting imbalance between the Group's cumulative entitlement and share of cumulative production less stock gives rise to an underlift or overlift.

Entitlement imbalances in under/overlift positions and the movements in inventory are included in production costs (Note 5). An overlift liability is measured on the basis of the cost of production and represents a provision for production costs attributable to the volumes sold in excess of entitlement. The underlift asset is measured at the lower of cost and net realisable value, consistent with IAS 2, to represent a right to additional physical inventory. A underlift of production from a field is included in current receivables and an overlift of production from a field is included in current liabilities.

INCOME TAX

Income tax expense represents the sum of the tax currently payable and deferred tax.

Current tax

The tax currently payable is based on taxable profit for the year. Taxable profit differs from profit as reported in the statement of profit or loss and other comprehensive income, because it excludes items of income or expense that are taxable or deductible in other years and it further excludes items that are not taxable or tax deductible. The Group's liability for current tax is calculated using tax rates (and tax laws) that have been enacted or substantively enacted, in countries where the Company and its subsidiaries operate, by the end of the reporting period.

Petroleum resource rent tax (PRRT)

PRRT incurred in Australia is considered for accounting purposes to be a tax based on income. Accordingly, current and deferred PRRT expense is measured and disclosed on the same basis as income tax.

PRRT is calculated at the rate of 40% of sales revenues less certain permitted deductions and is tax deductible for income tax purposes. For Australian corporate tax purposes, PRRT payment is treated as a deductible expense, while PRRT refund is treated as an assessable income. Therefore, for the purposes of calculating deferred tax, the PRRT tax rate is combined with the Australian corporate tax rate of 30% to derive a combined effective tax rate of 28%.

Malaysia Petroleum Income Tax (PITA)

PITA incurred in Malaysia is considered for accounting purposes to be a tax based on income derived from petroleum operations. Accordingly, current and deferred PITA expense is measured and disclosed on the same basis as income tax.

PITA is calculated at the rate of 38% of sales revenues less certain permitted deductions and deferred tax is calculated at the same rate.

Deferred tax

Deferred tax is recognised on temporary differences between the carrying amounts of assets and liabilities in the financial statements, and the corresponding tax bases used in the computation of taxable profit. Deferred tax liabilities are generally recognised for all taxable temporary differences and deferred tax assets are recognised to the extent that it is probable that taxable profits will be available, against which deductible temporary differences can be utilised. Such deferred tax assets and liabilities are not utilised if the temporary difference arises from goodwill or from the initial recognition (other than in a business combination) of other assets and liabilities in a transaction that affects neither the taxable profit nor the accounting profit.

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

Deferred tax assets arising from deductible temporary differences associated with such investments and interests, are only recognised to the extent that it is probable that there will be sufficient taxable profits against which to utilise the benefits of the temporary differences, and they are expected to reverse in the foreseeable future.

The carrying amount of deferred tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable profits will be available to allow all or part of the asset to be recovered.

Deferred tax is calculated at the tax rates that are expected to apply in the period when the liability is settled, or the asset realised, based on the tax rates (and tax laws) that have been enacted or substantively enacted, by the end of the reporting period. The measurement of deferred tax liabilities and assets reflects the tax consequences that would follow from the manner in which the Group expects, at the end of the reporting period, to recover or settle the carrying amount of its assets and liabilities.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to set off current tax assets against current tax liabilities and when they relate to income taxes levied by the same taxation authority and the Group intends to settle its current tax assets and liabilities on a net basis.

Current and deferred tax for the year

Current and deferred tax are recognised as an expense or income in profit or loss, except when they relate to items credited or debited outside profit or loss (either in other comprehensive income or directly in equity), in which case the tax is also recognised outside profit or loss (either in other comprehensive income or directly in equity, respectively).

Other taxes

Revenue, expenses, assets, and liabilities are recognised net of the amount of goods and services tax ("GST") or value added tax ("VAT") except:

- When the GST/VAT incurred on a purchase of goods and services is not recoverable from the taxation authority, in which case the GST/VAT is recognised as part of the cost of acquisition of the asset or as part of the expense item as applicable; and

- Receivables and payables, which are stated with the amount of GST/VAT included.

The net amount of GST/VAT recoverable from, or payable to, the taxation authority is included as part of receivables or payables in the consolidated statement of financial position.

CASH AND BANK BALANCES

Cash and bank balances comprise cash in hand and at bank, and other short-term deposits held by the Group with maturities of less than three months. Restricted cash and cash equivalents balances are those which meet the definition of cash and cash equivalents but are not available for use by the Group.

3. CRITICAL ACCOUNTING JUDGEMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

In the application of the Group's accounting policies, management is required to make judgments, estimates and assumptions about the carrying amounts of assets and liabilities that are not readily apparent from other sources. The estimates and associated assumptions are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognised in the period in which the estimate is revised, if the revision affects only that period, or in the period of the revision and future periods, if the revision affects both current and future periods.

Critical accounting judgments

In the application of the Group's accounting policies, management is required to make judgments, estimates and assumptions about the carrying amounts of assets and liabilities that are not readily apparent from other sources. The estimates and associated assumptions are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognised in the period in which the estimate is revised, if the revision affects only that period, or in the period of the revision and future periods, if the revision affects both current and future periods.

The following is the critical judgement, apart from those involving estimates (see below) that management has made in the process of applying the Group's accounting policies that have the most significant effect on the amounts recognised in the financial statements.

a) Acquisitions, divestitures and/or assignment of interests

The Group accounts for acquisitions and divestitures by considering if the acquired or transferred interest relates to that of an asset, or of a business as defined in IFRS 3 *Business Combinations* para B7, B8 and Appendix A, in so far as those principles do not conflict with the guidance in IFRS 11 *Joint Arrangements*. Accordingly, the Group considers if there is the existence of business elements as defined in IFRS 3 (e.g., inputs and substantive processes), or a group of assets that includes inputs and substantial processes that together significantly contribute to the ability to create outputs and providing a return to investors or other economic benefits. The justifications for this assessment on both acquisition of the CWLH Assets and the 10% remaining interest in the Lemang PSC have been set out in Notes 18 and 19, respectively.

b) Impairment of oil and gas properties and intangible exploration assets

The Group assesses each asset or cash-generating unit ('CGU') (excluding goodwill, which is assessed annually regardless of indicators) in each reporting period to determine whether any indication of impairment exists. Assessment of indicators of impairment or impairment reversal and the determination of the appropriate grouping of assets into a CGU or the appropriate grouping of CGUs for impairment purposes require significant management judgement. For example, individual oil and gas properties may form separate CGUs whilst certain oil and gas properties with shared infrastructure may be grouped together to form a single CGU. Alternative groupings of assets or CGUs may result in a different outcome from impairment testing. See Note 12 for details on how these groupings have been determined in relation to the impairment testing of oil and gas properties.

For the intangible exploration assets, the Group takes into consideration the technical feasibility and commercial viability of extracting a mineral resource and whether there is any adverse information that will affect the final investment decision.

Key sources of estimation uncertainty

The key assumptions concerning the future, and other key sources of estimation uncertainty at the end of the reporting period, 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) Deferred taxes

The Group recognises the net future economic benefit of deferred tax assets to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future and the carry forward of unutilised tax credits and unutilised tax losses can be utilised accordingly. Assessing the recoverability of deferred income tax, PRRT and PITA assets require the Group to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in each jurisdiction. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Group to realise the net deferred tax assets as recorded in the statement of financial position, could be impacted.

The carrying amount of the Group's deferred tax assets are disclosed in Note 26 to the financial statements.

Sensitivity analysis

Sensitivities have been run on the oil price assumption, with a 10% change to the price assumptions used at year end, sourced from independent third party, ERCE being considered a reasonable possible change for the purposes of sensitivity analysis. A 10% decrease/increase in oil price would not result in a change in the deferred tax asset recognised by the Group due to the unrecognised deferred tax assets being associated with the unwinding of provision of asset retirement obligations in the future during the decommissioning period. The Group is not expected to be in taxable profit position during the decommissioning period to enable it to utilise the unrecognised deferred tax assets at year end.

b) Reserves estimates

The Group's estimated reserves are management assessments, and are audited by an independent third party, which involves reviewing various assumptions, interpretations and assessments. These include assumptions regarding commodity prices, exchange rates, future production, transportation costs, climate related risks and interpretations of geological and geophysical models to make assessments of the quality of reservoirs and the anticipated recoveries. Changes in reported reserves can impact asset carrying amounts, the provision for restoration and the recognition of deferred tax assets, due to changes in expected future cash flows. Reserves are integral to the amount of depreciation, depletion and amortisation charged to the statement of profit or loss and other comprehensive income, and the calculation of inventory. Based on the analysis performed, management does not expect a 5% increase/decrease in the reserves estimates would significantly impact the carrying amounts of the assets and liabilities of the Group at year end. Management considers 5% movements to the existing reserves a reasonable assumption based on the historical technical adjustments during the annual reserves audit performed by an independent third party.

c) Impairment of oil and gas properties and intangible exploration assets

For the impairment assessment of oil and gas properties, management assesses the recoverable amounts using the FVLCOD approach. The post-tax estimated future cash flows are prepared based on estimated reserves, future production profiles, future hydrocarbon price assumptions and costs. The future hydrocarbon price assumptions used are highly judgemental and may be subject to increased uncertainty given climate change and the global energy transition. Management further takes into consideration the impact of climate change on estimated future commodity prices with the application of the Paris aligned price assumptions.

The carrying amounts of intangible exploration assets, oil and gas properties and right-of-use assets are disclosed in Notes 21, 22 and 24, respectively.

The Group recognises that the climate change and energy transition is likely to impact the demand for oil and gas, thus affecting the future prices of these commodities and the timing of decommissioning activities. This in turn may affect the recoverable amount of the Group's oil and gas properties and intangible exploration assets, and the carrying amount of the asset retirement obligations provision. The Group acknowledges that there is a range of possible energy transition scenarios that may indicate different outcomes for oil prices. There are inherent limitations with scenario analysis and it is difficult to predict which, if any, of the scenarios might eventuate.

The Group has assessed the potential impacts of climate change and the transition to a lower carbon economy in preparing the consolidated financial statements, including the Group's current assumptions relating to demand for oil and gas and their impact on the Group's long-term price assumptions, and also taking into consideration the forecasted long-term prices and demand for oil and gas under the Paris aligned scenarios. The key estimates for reserves estimates and impairment of oil and gas properties will be included in the Group's FY2022 Annual Report which will be released on 25 May 2023.

Management will continue to review various price assumptions such as Paris aligned price assumptions and demand in line with the scenarios based on decrease to emissions as the energy transition progresses and will take into consideration in the future impairment assessments. Further disclosures will be included under the Sustainability Review section of the Group's FY2022 Annual Report which will be released on 25 May 2023.

Sensitivity analyses

Management assessed the impact of a change in cash flows in impairment testing arising from a 10% reduction in price assumptions used at year end, sourced from independent third party, ERCE. The forecasted price assumptions are US$84.5/bbl in 2023, US$82.1/bbl in 2024, US$79.9/bbl in 2025, US$80.6/bbl in 2026 and an average of US$89.7/bbl from 2027 onwards. Management is of the view that these price assumptions are aligned with the Group's latest internal forecasts, reflecting long-term views of global supply and demand. The price assumptions used are reviewed and approved by management. Based on the analysis performed, management concluded that a 10% price reduction in isolation under the various scenarios would not impact the carrying amount of the Group's oil and gas properties.

Management also assessed the impact of the change in cash flows used in impairment testing arising from the application of the oil price assumptions under the Net Zero Emissions by 2050 Scenario plus the inclusion of carbon cost estimates. Further details will be included under the Sustainability Review section of the Group's FY2022 Annual Report which will be released on 25 May 2023. The oil prices under the Net Zero Emissions by 2050 Scenario for each asset are as follow:

	2023	**2024**	**2025**	**2026**	**2027**	**2028 onwards**
	US$/bbl	**US$/bbl**	**US$/bbl**	**US$/bbl**	**US$/bbl**	**US$/bbl**
Montara	88.3	84.2	81.8	73.8	65.8	45.9
Stag	88.3	84.2	81.8	73.8	65.8	44.6
CWLH Assets	88.3	84.2	81.8	73.8	65.8	46.7
PenMal Assets – PM323 PSC	88.3	84.2	81.8	73.8	65.8	57.8
PenMal Assets – PM329 PSC	88.3	84.2	81.8	73.8	65.8	47.5
Lemang PSC	88.3	84.2	81.8	73.8	65.8	45.3

The carbon costs estimates under the Net Zero Emissions by 2050 Scenario for each asset are as follows:

	2023 US$'000	2024 US$'000	2025 US$'000	2026 US$'000	2027 US$'000	2028 onwards US$'000
Montara	756	3,469	5,566	7,571	9,666	54,536
Stag	-	-	1,715	2,295	2,802	15,415
CWLH Assets	115	427	692	964	1,119	6,855
PenMal Assets – PM323 PSC	572	1,128	1,700	2,176	-	-
PenMal Assets – PM329 PSC	303	597	890	1,182	1,474	15,813
Lemang PSC	-	-	210	555	829	41,257

Based on the analysis performed, the reduction in operating cash flows under the Net Zero Emissions by 2050 Scenario would not result in an impairment on the carrying amount of the Group's oil and gas properties.

The oil price sensitivity analyses above do not, however, represent management's best estimate of any impairments that might be recognised as they do not fully incorporate consequential changes that may arise, such as reductions in costs and changes to business plans, phasing of development, levels of reserves and resources, and production volumes. As an example, as price reduces, it is likely that costs would decrease across the industry. The oil price sensitivity analysis therefore does not reflect a linear relationship between price and value that can be extrapolated.

Management also tested the impact of a 5% (2021: 5%) change to the discount rate used of 8.99% (2021: 10%) for impairment testing of oil and gas properties, and concluded that a 5% increase/decrease in the discount rate will not result in impairment as the net present value of either outcome is above the carrying amount of the Group's oil and gas properties at year end.

d) Asset restoration obligations

The Group estimates the future removal and restoration costs of oil and gas production facilities, wells, pipelines and related assets at the time of installation of the assets and reviewed subsequently at the end of each reporting period. In most instances the removal of these assets will occur many years in the future.

The estimate of future removal costs is made considering relevant legislation and industry practice and requires management to make judgments regarding the removal date, the extent of restoration activities required and future costs and removal technologies.

The carrying amounts of the Group's asset restoration obligations is disclosed in Note 35 to the financial statements.

While the transition to a lower carbon economy is currently ongoing, oil and gas demand is expected to remain a key element of the energy mix in the foreseeable future as oil and gas will still remain as one of primary energy sources globally while countries work to reduce emissions gradually over the coming years to achieve stated emission targets.

Therefore, given the useful lives of the Group's current portfolio of oil and gas assets of up to 2040, management does not expect the potential decline on oil prices as a result of climate change and the transition to a lower carbon economy will have a material adverse change to the operating cash flows of the Group during the lives of those assets and thus the carrying amounts of the Group's assets and liabilities will not be significantly impacted, as evidenced by the sensitivity analyses performed using price assumptions under the Net Zero Emissions by 2020 Scenario as disclosed under bullet point c) above.

Sensitivity analyses

Sensitivities have been run on the discount rate assumption, with a 1% change being considered a reasonable possible change for the purposes of sensitivity analysis. A 1% reduction in discount rate would increase the liability by US$53.3 million and a 1% increase in discount rate would decrease the liability by US$47.3 million. A 10% increase in current estimated costs would increase the liability by US$45.7 million and a 10% decrease in current estimated costs would decrease the liability by US$45.7 million. A one year deferral to the estimated decommissioning year of each asset as disclosed in Note 35 would decrease the liability by US$5.6 million and an acceleration of one year to the estimated decommissioning year as disclosed in Note 35 would increase the liability by US$5.7 million. Management considers the 1% movement to the discount rate, 10% to the current estimated costs and one year movement to the estimated decommissioning year a reasonable assumption based on the historical adjustments to the risk-free rates, base decommissioning costs and estimated decommissioning year.

4. REVENUE

The Group presently derives its revenue from contracts with customers for the sale of oil and gas products.

In line with the revenue accounting policies set out in Note 2, all revenue is recognised at a point in time.

	2022 USD'000	2021 USD'000
Liquids revenue	418,483	339,210
Gas revenue	3,119	984
	421,602	**340,194**

There was no hedge contract entered into by the Group during the year. In 2021, the Group entered into Australian commodity swap contracts hedging approximately 30% of its planned production for the period January to June. The commodity swap contracts were measured at FVTPL as opposed to hedge accounting, in part because the swap contracts covered a short time span, commenced and matured in the same reporting period. The swap contracts incurred a loss of US$4.6 million during the year which is recorded as other expense (Note 10).

5. PRODUCTION COSTS

	2022 USD'000	2021 Restated* USD'000
Operating costs	100,664	62,399
Workovers	10,190	67,006
Logistics	31,895	20,212
Repairs and maintenance	60,174	44,417
Tariffs and transportation costs	8,341	2,809
Underlift, overlift and crude inventories movement	39,436	15,053
	250,700	**211,896**

*Certain 2021 comparative information has been restated. Please refer to Note 45.

Operating costs predominately consists of offshore manpower costs of US$26.1 million (2021: US$26.8 million), chemicals, services, supplies and other production related costs for a total of US$38.3 million (2021: US$21.1 million), Malaysian supplementary payments totalled US$24.5 million (2021: US$8.3 million), insurance of US$4.8 million (2021: US$2.7 million) and non-operated assets production costs of US$3.3 million (2021: US$1.2 million). The Malaysian supplementary payments are payable under the terms of PSCs based on the Group's entitlement to profit from oil and gas. It is calculated at 70% of the excess revenue over the base price of the sale of oil as set out under the terms of PSCs. These supplementary payments are made to PETRONAS.

Underlift, overlift and crude inventories movement resulted in an expense of US$39.4 million (2021: US$15.1 million), mostly related to the CWLH Assets acquired in November 2022. At closing of the acquisition on 1 November 2022, the Group acquired an underlift position with a fair value of US$27.3 million (Note 18). The underlift position was recognised as an expense following a lifting which occurred in the middle of November 2022. At the year end, the Group is in an overlift position of 205,510 bbls (2021: underlift of 88,398 bbls) and accordingly has recognised a production expense of US$6.8 million (2021: production credit of US$1.5 million), measured at the lower of cost and net realisable value of US$32.94/bbl (2021: US$16.77/bbl). The overlift position at 2022 year end will unwind in 2023 based on the subsequent net productions entitled to the Group. The underlift position at 2021 year end unwound in 2022.

Workovers in current year are recurring in nature. In 2021, the costs included the Montara subsea workovers for the Skua 10 and Skua 11 wells of US$47.2 million, net of insurance claim receivable of US$10.3 million on the well control claim for the Skua 11 well workovers.

Repairs and maintenance in current year include Montara Skua 11 repairment works, solar engine change out and emergency tank repairs. In 2021, the costs included a once-in-every-three-year subsea flowline inspection and Swift North subsea control module change out at Montara and a once-in-five-year changeout of the under-buoy hose at Stag which totalled US$6.6 million.

6. DEPLETION, DEPRECIATION AND AMORTISATION ("DD&A")

	2022 USD'000	2021 USD'000
Depletion and amortisation (Note 22):	45,288	62,586
Depreciation of:		
Plant and equipment (Note 23)	616	508
Right-of-use assets (Note 24)	13,015	11,191
Crude inventories movement	2,915	5,930
	61,834	**80,215**

The depreciation of right-of-use assets in 2021 included US$1.5 million associated with the Skua 10 and 11 workovers.

The crude inventories movement represents additional/reversal of depletion expense recognised during the year based on the net movement of crude inventories at year end against beginning of the year. For the purpose of the consolidated statement of cash flows, this amount has been excluded from the movement in working capital.

The depletion charge is calculated based on units of production and adjusted based on the net movement of crude inventories at year end against beginning of the year. In 2022, the adjustment was for 94,989 bbls of crude inventories at the end of 2022 compared to 274,103 bbls at the end of 2021, mostly due to the cessation of production at Montara since August 2022, which resulted in an additional depletion charge of US$2.9 million.

7. ADMINISTRATIVE STAFF COSTS

	2022 USD'000	2021 USD'000
Wages, salaries and fees	24,825	21,066
Staff benefits in kind	3,422	3,051
Share-based compensation	971	951
	29,218	**25,068**

The compensations of directors and key management personnel are included in the above and disclosed separately in Notes 9 and 44, respectively.

8. STAFF NUMBERS AND COSTS

The average number of employees (including executive directors) was:

	2022 Number	2021 Number
Production	152	125
Technical	206	143
Administration	2	3
Management	9	7
	369	**278**

Staff costs are split between production costs (Note 5) for offshore personnel and administrative staff costs (Note 7) for onshore personnel.

Their aggregate remuneration comprised:

	2022 USD'000	2021 USD'000
Wages and salaries	45,548	39,158
Social security costs	199	186
Defined contribution pension costs	3,573	3,177
Share-based compensation	971	951
	50,291	**43,472**
Contractors and consultants costs	4,976	8,363
	55,267	**51,835**

9. DIRECTORS' REMUNERATION AND TRANSACTIONS

	2022 USD'000	2021 USD'000
Directors' remuneration		
Salaries, fees, bonuses and benefits in kind	2,253	3,093
Gains on exercise of options	-	1,259
Amounts receivable under long term incentive plans	340	278
Money purchase pension contributions	78	96
	2,671	**4,726**
Remuneration of the highest paid Director:		
Salaries, fees, bonuses and benefits in kind	1,266	1,516
Gains on exercise of options	-	481
Amounts receivable under long term incentive plans	271	302
Money purchase pension contributions	65	63
	1,602	**2,362**

	Number	Number
The number of Directors who:		
Are members of a defined benefit pension scheme	-	-
Are members of a money purchase pension scheme	2	2
Exercised options over shares in the Company	-	2
Had awards receivable in the form of shares under a long-term incentive scheme	2	2

Since 2021, the Non-Executive Directors were not granted any options/shares under the Company's long term incentive plans.

10. OTHER EXPENSES

	2022 USD'000	2021 USD'000
Corporate costs	10,405	11,487
Change in provision – Lemang PSC contingent payments	7,333	-
Allowance for slow moving inventories	3,768	2,624
Assets written off	212	5,332
Net foreign exchange loss	442	950
Loss on valuation of oil derivatives	-	4,633
Other expenses	145	1,155
	22,305	**26,181**

Corporate costs consists of recurring operating expenses of the Group plus certain non-recurring costs such as business development costs of US$1.2 million (2021: US$3.2 million), professional fees in relation to internal reorganisation of US$0.2 million (2021: US$1.1 million) and external funding sourcing of US$0.2 million (2021: nil). The non-recurring corporate costs in 2021 included project transition costs of US$0.9 million.

The change in provision associated with the Lemang PSC contingent payments represents additional contingent payments related to the future Dated Brent prices and Saudi CP prices during the first and second years of production in the Lemang PSC (Note 35).

In 2021, the Group incurred a loss on valuation of oil derivatives that arose from the Australian commodity swap contracts entered for the period January to June. For the purpose of the consolidated statement of cash flows, the US$4.6 million included a reversal of loss on oil derivatives of US$0.5 million from 2020.

The Group has written off the office equipment located in the New Zealand office following the termination of the Maari acquisition in October 2022. The amount in prior year included the write-off of intangible exploration assets of US$5.3 million previously capitalised as they were not expected to generate future economic benefits.

For the purpose of the consolidated statement of cash flows, the net foreign exchange loss reported above in 2022 included a net unrealised loss of US$0.1 million.

11. AUDITOR'S REMUNERATION

The analysis of the auditor's remuneration is as follows:

	2022 USD'000	2021 USD'000
Fees payable to the Company's auditor for the audit of the parent company and Group's consolidated financial statements	517	413
Audit fees of the subsidiaries	390	415
	907	**828**

No fees were paid to the Group's auditors for non-audit services for either the Group or the Company in 2021 or 2022.

The audit fee in prior year represented the actual finalised fee agreed with the auditors.

12. IMPAIRMENT OF ASSETS

	2022 USD'000	2021 USD'000
Impairment of oil and gas properties (Note 22)	13,534	-

The impairment expense of US$13.5 million in current year relates to the oil and gas properties associated with the PenMal Assets's non-operated PSCs, which was treated as a single cash-generating unit, following the decision made by the operator to shut-in production after FPSO class suspension in February 2022. Management does not expect future economic inflows from the non-operated PSCs due to the uncertainty in respect to any potential restart date for production as at the 2022 year end until mutual agreement is reached between the Group and the operator on the future plans of the non-operated PSCs. Accordingly, the value in use of the non-operated PSCs is valued at nil as at the 2022 year end. The impairment was made in relation to the producing asset of the Group located in Southeast Asia as disclosed in Note 40.

On 14 April 2023, the Group signed a Withdrawal Agreement and Operatorship Transfer and Assistance Agreement with the previous operator, which sets out the terms and conditions of the Group's assumption of operatorship and the previous operator's continuing obligations and liabilities with respect to the non-operated PSCs. In particular, the previous operator will pay the Group a sum of US$50.2 million through two instalments in August 2023 and January 2024, respectively, which will cover the previous operator's share of well preservation costs, well abandonment liabilities and reinstatement of the pipeline connecting the Penara oilfields with the FPSO. The Group sees the redevelopment of the non-operated PSCs at a 100% interest as a potentially significant opportunity for the Group. A redevelopment plan is currently being prepared and the Group plans to submit it to the regulator by mid-2023.

13. OTHER INCOME

	2022 USD'000	2021 USD'000
Interest income	881	80
Net foreign exchange gain	341	2,525
Insurance claims receipt	17,977	-
Other income	8,834	5,077
	28,033	**7,682**

Insurance claims receipt in 2022 represents the claim received at Montara for the compensation for the loss of production relating to drilling activities at the two Skua field wells in 2020. These insurance claims were settled and the cash was received in Q4 2022.

Other income consists of rental income from a helicopter rental contract (a right-of-use asset) to a third party of US$5.0 million (2021: US$4.5 million) and US$0.9 million related to income recognised for previously unrecognised amount due from joint arrangement partner.

For the purpose of the consolidated statement of cash flows, the net foreign exchange gain reported above in 2021 included a net unrealised gain of US$1.8 million.

14. FINANCE COSTS

	2022 USD'000	2021 USD'000
Interest expense	5	150
Accretion expense for asset retirement obligations (Note 35)	8,314	5,920
Changes in fair value of:		
PenMal Assets contingent payment (Note 35)	1,571	124
Lemang PSC contingent payments (Note 35)	349	314
Interest expense on lease liabilities	769	1,222
Accretion expense from non-current Lemang PSC VAT receivables	314	-
Other finance costs	86	1,345
	11,408	**9,075**

The second contingent payment arising from the acquisition of the PenMal Assets was recognised in full for an amount of US$3.0 million as at 31 December 2022 (Note 35), resulting in an increase in the provision of US$1.6 million. The amount was therefore recognised as an accrual as at 2022 year end.

The changes in fair value of the provision associated with the Lemang PSC of US$0.3 million represents adjustments to the previous recognised contingent payments, reflecting the effect of the time value of money.

Other finance costs in 2021 included accretion expense of US$1.2 million generated from an Australian Taxation Office ("ATO") 2019 repayment plan of US$43.3 million to support companies impacted by COVID-19. The repayment schedule was between December 2020 and June 2022 but the plan was fully repaid in May 2022.

15. OTHER FINANCIAL GAINS

	2022 USD'000	2021 USD'000
Accretion income from Australian tax repayment plan	1,904	-
Accretion income from non-current Lemang PSC VAT receivables	-	266
	1,904	**266**

Accretion income in 2022 was generated from the Australian Taxation Office ("ATO") 2019 repayment plan due to early settlement by the Group in May 2022.

16. INCOME TAX EXPENSE

	2022 USD'000	2021 Restated* USD'000
Current tax		
Corporate tax charge/(credit)	15,656	(486)
Under/(Over)provision in prior year	666	(270)
	16,322	**(756)**
Australian petroleum resource rent tax ("PRRT")	(1,121)	(1,374)
Malaysian petroleum income tax ("PITA")	11,899	9,469
	27,100	**7,339**
Deferred tax		
Corporate tax	14,149	5,246
PRRT	7,032	3,371
PITA	5,737	(3,176)
	26,918	**5,441**
	54,018	**12,780**

*Certain 2021 comparative information has been restated. Please refer to Note 45.

Jadestone Energy plc's tax domicile is Singapore and is subjected to Singapore's domestic corporate tax rate of 17%. Subsidiaries are resident for tax purposes in the territories in which they operate.

The Australian corporate income tax rate is applied at 30% of Australian corporate taxable income. PRRT is calculated at 40% of sales revenue less certain permitted deductions and is tax deductible for Australian corporate income tax purposes.

The Malaysian corporate income tax is applied at 24% on non-petroleum taxable income. PITA is calculated at 38% of sales revenue less certain permitted deductions and is tax deductible for Malaysian corporate income tax purposes.

During the year, Stag recorded a net PRRT expense of US$5.9 million (2021: US$2.0 million).

As at year end, Montara has US$3.5 billion (2021: US$3.4 billion) of unutilised carried forward PRRT credits. Based on management's latest forecasts, the historic accumulated PRRT net losses are larger than cumulative future expected PRRT taxable profits. Accordingly, Montara is not anticipated to incur any PRRT expense in the future of the asset.

PenMal Assets recorded PITA expense of US$17.6 million during the year (2021: US$6.3 million).

The tax recoverable of US$9.7 million as at year end includes of a PITA receivable of US$5.1 million which arose from pre-economic effective date of the PenMal Assets acquisition which will be payable to SapuraOMV following the receipt of a tax refund. The Group has recognised the payable to SapuraOMV as at year end.

The tax expense on the Group's profit/(loss) differs from the amount that would arise using the standard rate of income tax applicable in the countries of operation as explained below:

	2022 USD'000	2021 Restated* USD'000
Profit/(Loss) before tax	**62,540**	**(4,293)**
Tax calculated at the domestic tax rates applicable to the profit/loss in the respective countries (Australia 30%, Malaysia 24% & 38%, Canada 27% and Singapore 17%)	20,292	1,906
Effects of non-deductible expenses	9,513	5,845
Effect of PRRT/PITA tax expense	10,778	8,095
Deferred PRRT/PITA tax expense	12,769	196
Effect of unutilised tax losses recognised as deferred tax asset	-	(2,992)
Under/(Over)provision in prior year	666	(270)
Tax expense for the year	**54,018**	**14,822**

17. PROFIT/(LOSS) PER ORDINARY SHARE

The calculation of the basic and diluted loss per share is based on the following data:

	2022 USD'000	2021 Restated* USD'000
Profit/(Loss) for the purposes of basic and diluted per share, being the net profit/(loss) for the year attributable to equity holders of the Company	8,522	(17,073)

*Certain 2021 comparative information has been restated. Please refer to Note 45.

	2022 Number	2021 Number
Weighted average number of ordinary shares for the purposes of basic EPS	461,959,228	463,567,519
Effect of diluted potential ordinary shares – share options	3,876,548	-
Effect of diluted potential ordinary shares – performance shares	334,163	-
Effect of diluted potential ordinary shares – restricted shares	202,823	-
Weighted average number of ordinary shares for the purposes of dilutive EPS	**466,372,762**	**463,567,519**

In 2021, 6,640,985 of weighted average potentially dilutive ordinary shares available for exercise from in the money vested options, associated with share options were excluded from the calculation of diluted EPS, as they are anti-dilutive in view of the loss for the year.

In 2021, 899,306 of weighted average contingently issuable shares associated under the Company's performance share plan based on the respective performance measures up to year end were excluded from the calculation of diluted EPS, as they are anti-dilutive in view of the loss for the year.

In 2021, 140,965 of weighted average contingently issuable shares under the Company's restricted share plan were excluded from the calculation of diluted EPS, as they are anti-dilutive in view of the loss for the year.

Profit/(Loss) per share (US$)	2022	2021 Restated*
- Basic and diluted	0.02	(0.04)

18. ACQUISITION OF INTEREST IN CWLH JOINT OPERATION

18.1 Effective Date and Acquisition Date

On 28 July 2022, the Group executed a sale and purchase agreement ("SPA") with BP Developments Australia Pty Ltd ("BP") to acquire BP's non-operated 16.67% working interest in the Cossack, Wanaea, Lambert and Hermes oil field development (the "North West Shelf Project" or "CWLH Assets"), offshore Australia. The initial cash consideration was US$20.0 million plus two contingent payments of US$2.0 million each if the annual average Dated Brent price is equal to or above US$50/bbl in 2022 and US$60/bbl in 2023. The first contingent payment materialised as at year end and was paid in January 2023. Based on current oil prices and the outlook in the oil market, management believes the second contingent payment (in case Dated Brent price exceeds US$60/bbl) will likely materialise at the end of 2023.

In addition to the consideration and contingent payments, as part of this transaction, the Group is committed to pay a total of US$82.0 million into a decommissioning trust fund administered by the operator of the CWLH Assets. The first tranche of US$41.0 million was paid immediately prior to closing of the acquisition and two further payments of US$20.5 million each are due upon Offshore Petroleum & Greenhouse Gas Storage Act (2006) title registration, or as soon as practical after 31 December 2022, and before 31 December 2023, respectively.

The acquisition completed on 1 November 2022, pending the condition subsequent of National Offshore Petroleum Titles Administrator's approval, which is expected to receive in the second quarter of 2023. The acquisition has an economic effective date of 1 January 2020, which meant the Group was entitled to net cash generated since effective date to completion date, resulting in net cash receipts of US$6.9 million at completion on 1 November 2022.

The legal transfer of ownership and control of the non-operated 16.67% working interest in the CWLH Assets occurred on the date of completion, 1 November 2022 (the "Acquisition Date"). Therefore, for the purpose of calculating the purchase price allocation, management has assessed the fair value of the assets and liabilities associated with the CWLH Assets as at the Acquisition Date.

18.2 Acquisition of a 16.67% non-operated working interest

The CWLH Assets contain inputs and processes, which when combined has the ability to contribute to the creation of outputs (oil). Accordingly, the CWLH assets constitute a business and as a consequence, we have accounted for our acquisition of a 16.67% working interest in those assets using the accounting principles of business combinations accounting as set out in IFRS 3, and other IFRSs, in so far as those principles do not conflict with the guidance in IFRS 11.

A purchase price allocation exercise was performed to identify, and measure at fair value, the assets acquired and liabilities assumed in the business combination. The consideration transferred was measured at fair value. The Group has adopted the definition of fair value under IFRS 13 *Fair Value Measurement* to determine the fair values, by applying Level 3 of the fair value measurement hierarchy.

18.3 Fair value of consideration

After taking into account various adjustments the net consideration for the CWLH Assets resulted in a cash receipt of US$6.9 million, as set out below:

	USD'000
Asset purchase price	20,000
Closing statement adjustments	(26,953)
Net cash receipts from the acquisition	**(6,953)***

Management assessed the fair value of the two deferred contingent payments by considering the forecasted Dated Brent prices and expects that both contingent payments will materialise. The contingent payment due at the end of 2023 was discounted using the Australian risk-free rate of 3.08%. The total fair value of these contingent payments was calculated at US$3.9 million, representing US$2.0 million and US$1.9 million for the 2022 and 2023 deferred contingent payments, respectively. The assessment of the contingent payments was performed as at 1 November 2022, based on the facts and circumstances existed as at that date. The 2022 payment materialised at year end and the amount was recognised in full as an accrual at year end. The payment was subsequently made in January 2023.

Fair value of purchase consideration	**USD'000**
Asset purchase price	20,000
Closing statement adjustments	(26,953)
Net cash receipts from the acquisition	**(6,953)***
Deferred contingent consideration	3,940
Fair value of purchase consideration	**(3,013)**

* For the purpose of the consolidated statement of cash flows, the Group received US$5.8 million from BP on the Acquisition Date, with the remaining US$1.2 million recognised as a receivable as at 2022 year end. The cash amount was received in February 2023.

The Group considers that the purchase consideration and the transaction terms to be reflective of fair value for the following reasons:

- Open and unrestricted market: there were no restrictions in place preventing other potential buyers from negotiating with BP during the sales process period and there were a number of other interested parties in the formal sale process;
- Knowledgeable, willing but not anxious parties: both the Group and BP are experienced oil and gas operators under no duress to buy or sell. The process was conducted over several months which gave both parties sufficient time to conduct due diligence and prepare analysis to support the transaction; and
- Arm's length nature: the Group is not a related party to BP. Both parties had engaged their own professional advisors. There is no reason to conclude that the transaction was not transacted at arm's length.

18.4 Assets acquired and liabilities assumed at the date of acquisition

During the year, the Group has completed the provisional purchase price assessment ("PPA") to determine the fair values of the net assets acquired within 12 months from the Acquisition Date. The adjusted fair values of the identifiable assets and liabilities as at the Acquisition Date were:

	USD'000
Asset	
Non-current asset	
Oil and gas properties (Note 22)	41,976
Current asset	
Trade and other receivables	27,870*
	69,846
Liabilities	
Non-current liabilities	
Provision for asset retirement obligations (Note 35)	60,158
Deferred tax liabilities	12,593
Current liability	
Trade and other payables	108
	72,859
Net identifiable liabilities assumed	**(3,013)**

* Trade and other receivables consisted of a gross underlift position of 314,078 bbls acquired by the Group, with a fair value of US$27.3 million, measured at the prevailing market price of US$86.68/bbl. The underlift position was recognised as an expense following a lifting which occurred in the middle of November 2022. The balance also included a gross cash overcall position owing by the operator of US$0.6 million as at the acquisition date. The overcall position will be unwound in the future based on the joint arrangement expenditures claim raised by the operator. No loss allowances have been recognised in respect to trade and other receivables.

18.5 Impact of acquisition on the results of the Group

The Group's 2022 results included US$56.6 million of revenue and US$8.2 million of after tax profit attributable to the CWLH Assets.

Acquisition-related costs amounting to US$0.5 million have been excluded from the consideration transferred and have been recognised as an expense in the period, within "other expenses" line item in the consolidated statement of profit or loss and other comprehensive income.

Had the business combination been effected at 1 January 2022, and based on the performance of the business during 2022 under BP, the Group would have generated revenues of US$109.6 million and an estimated net profit after tax of US$29.5 million.

The Directors of the Group consider these "pro-forma" numbers to represent an approximate measure of the performance of the combined Group on an annualised basis and to provide a reference point for comparison in future periods.

19. ACQUISITION OF 10% INTEREST IN LEMANG PSC

19.1 Acquisition date

On 23 November 2022, the Group completed the acquisition of the remaining 10% interest in the Lemang PSC. As a result, Jadestone's interest (pre local government back-in rights) in the Lemang PSC has increased to 100%.

The 10% interest was acquired through the execution of a Settlement and Transfer Agreement ("STA") between the Group and PT Hexindo Gemilang Jaya ("Hexindo"). In return for the transfer of Hexindo's 10% stake, the Group released Hexindo from unpaid amounts of US$1.4 million relating to Hexindo's interest in the Lemang PSC, which consisted of US$0.4 million (Note 28) generated since 11 December 2020 when the Group first acquired the 90% working interest in the Lemang PSC up to the STA date of 23 November 2021, plus US$1.0 million which arose prior to 11 December 2020. Additionally, the Group paid a cash consideration of US$0.5 million (inclusive of transfer taxes, which the Group has remitted directly to the Indonesian government).

19.2 Asset acquisition

Management has concluded that the acquisition of 10% interest in the Lemang PSC represents an asset acquisition as the Lemang PSC does not come with an organised workforce, and the Group does not take over any process in the form of a system, protocol or standards to contribute to the creation of outputs. Hence, the acquisition does not fall within the definition of a business acquisition under IFRS 3. Therefore, the assets acquired and liabilities assumed in the acquisition of 10% interest in the Lemang PSC, and the consideration transferred have been measured at fair value, in accordance to the definition of fair value under IFRS 13 *Fair Value Measurement*.

19.3 Assets acquired and liabilities assumed at the date of acquisition

The fair value of the identifiable assets and liabilities associated with the 10% interest in the Lemang PSC, acquired and assumed as at the date of acquisition, were:

	USD'000
Asset	
Non-current assets	
Oil and gas properties (Note 23)	1,414
VAT receivables	1,338
Current assets	
Trade and other receivables	15
Inventories	26
	2,793
Liabilities	
Non-current liability	
Provision for asset retirement obligations (Note 36)	337
Current liability	
Trade and other payables	598
	935
Net identifiable assets acquired	**1,858**

The provision for asset restoration obligations assumed by the Group is associated with historical oil production by Mandala Energy that ceased in 2016, prior to the acquisition of the 90% operated interest by the Group in December 2020. The obligation was assumed following the acquisition, and the decommissioning expenditure is expected to be incurred from 2034, at the end of the life of the planned gas development.

20. ACQUISITION OF SAPURAOMV (PM) INC.

20.1 Effective Date and Acquisition Date

In 2021, the Group executed a sale and purchase agreement ("SPA") with SapuraOMV Upstream (PM) Sdn Bhd ("SapuraOMV") to acquire the entire share capital of SapuraOMV (PM) Inc. for a cash consideration of US$20.0 million, comprising initial price of US$9.0 million, plus contingent payments and customary adjustments of US$11.0 million (see Note 20.3). There were two contingent payments to SapuraOMV of US$3.0 million each related to the annual average Dated Brent price equal or above US$65/bbl in 2021 and US$70/bbl in 2022. The first contingent payment was paid in January 2022 and the second contingent payment was materialised in 2022 and was paid in January 2023.

Subsequent to the acquisition, the name of SapuraOMV (PM) Inc. was changed to Jadestone Energy (PM) Inc. ("JEPM").

20.2 Business acquisition

Management has concluded that the acquisition of JEPM is that of a business as defined in IFRS 3 *Business Combinations*. JEPM contains inputs and processes, which when combined has the ability to contribute to the creation of outputs (oil and gas). Accordingly, the transaction has been accounted for as a business combination.

As a result, the Group has applied the acquisition method of accounting as at the Acquisition Date. A purchase price allocation exercise was performed to identity, and measure at fair value, the assets acquired and liabilities assumed in the business combination. The consideration transferred was measured at fair value. The Group has adopted the definition of fair value under IFRS 13 *Fair Value Measurement* to determine the fair values. by applying Level 3 of the fair value measurement hierarchy.

20.3 Fair value of consideration transferred

The fair value consideration for the PenMal Assets reflected a net cash receipt of US$9.2 million, as set out below:

	USD'000
Asset purchase price	9,000
Crude inventory value	3,236
Cash at bank, 1 January 2021	8,091
Closing statement adjustments	(294)
Cash payment on Acquisition Date	**20,033**
Less: cash and bank balances acquired, 1 August 2021	(29,252)
Net cash receipts from the acquisition	**(9,219)**

The crude inventory was measured at the market value and the cash at bank represents the cash on hand, as at the economic effective date of 1 January 2021.

The closing statement adjustments relates to permitted leakages of US$0.3 million of audited intercompany charges that relate to SapuraOMV Group (pre 1 January 2021).

Fair value of purchase consideration	**USD'000**
Asset purchase price	9,000
Crude inventory value	3,236
Cash at bank	8,091
Closing statement adjustments	(294)
Cash payment on Acquisition Date	**20,033**
Working capital adjustment	(1,059)
Deferred contingent consideration	4,305
Fair value of purchase consideration	**23,279**

The Group considers that the purchase consideration and the transaction terms to be reflective of fair value for the following reasons:

- Open and unrestricted market: there were no restrictions in place preventing other potential buyers from negotiating with SapuraOMV during the sales process period and there were a number of other interested parties in the formal sale process;

- Knowledgeable, willing but not anxious parties: both the Group and SapuraOMV are experienced oil and gas operators under no duress to buy or sell. The process was conducted over several months which gave both parties sufficient time to conduct due diligence and prepare analysis to support the transaction; and

- Arm's length nature: the Group is not a related party to SapuraOMV. Both parties had engaged their own professional advisors. There is no reason to conclude that the transaction was not transacted at arm's length.

20.4 Assets acquired and liabilities assumed at the date of acquisition

During the year, the Group has completed the purchase price assessment ("PPA") to determine the fair values of the net assets acquired within the stipulated time period of 12 months from the Acquisition Date, in accordance with IFRS 3. The adjusted fair values of the identifiable assets and liabilities as at the Acquisition Date were:

	USD'000
Asset	
Non-current assets	
Oil and gas properties (Note 22)	21,744
Other receivables	42,092*
Deferred tax assets	10,343
Current assets	
Inventories	2,853
Trade and other receivables	21,276
Tax recoverable	10,226
Cash and bank balances	29,252
	137,786
Liabilities	
Non-current liabilities	
Provision for asset retirement obligations (Note 35)	91,552
Deferred tax liabilities	6,177
Current liability	
Trade and other payables	16,778
	114,507
Net identifiable assets acquired	**23,279**

* Other receivables represent the accumulated CESS paid to the Malaysian regulator for operated licences, which will be reclaimable by the Group in the future following the commencement of decommissioning activities.

20.5 Impact of acquisition on the results of the Group

Included in the Group's revenue and after tax loss in 2021 was US$46.6 million and a profit of US$6.5 million attributable to the PenMal Assets, respectively.

Acquisition-related costs amounting to US$0.7 million have been excluded from the consideration transferred and have been recognised as an expense in the period, within "other expenses" line item in the consolidated statement of profit or loss and other comprehensive income.

Had the business combination been effected at 1 January 2021, and based on the performance of the business during 2021 under SapuraOMV's operatorship, the Group would have generated revenues of US$107.2 million and an estimated net profit after tax of US$29.6 million.

The Directors of the Group consider these "pro-forma" numbers to represent an approximate measure of the performance of the combined Group on an annualised basis and to provide a reference point for comparison in future periods.

21. INTANGIBLE EXPLORATION ASSETS

	USD'000
Cost	
As at 1 January 2021	151,125
Additions	3,934[(a)]
Change in asset retirement obligations (Note 35)	(44)[(b)]
Reversal	(6,059)[(c)]
Written off	(55,715)[(d)]
As at 31 December 2021	**93,241**
Additions	3,582[(a)]
Transfer	(18,895)[(e)]
As at 31 December 2022	**77,928**
Impairment	
As at 1 January 2021	50,455
Written off	(50,455)
As at 31 December 2021 and 31 December 2022	**-**
Net book value	
As at 1 January 2021	**100,670**
As at 31 December 2021	**93,241**
As at 31 December 2022	**77,928**

[(a)] For the purpose of the consolidated statement of cash flows, current year expenditure on intangible exploration assets of US$0.3 million remained unpaid as at 31 December 2022 (2021: US$0.1 million).

(b) The change in asset retirement obligations of US$0.04 million in 2021 related to assets at the Lemang PSC.

(c) The US$6.0 million reversal in 2021 related to an overprovision of costs owed to a third party contractor. The overprovision was identified following an assessment of actual costs incurred.

(d) In November 2020, Total, as operator of SC56 voluntarily surrendered a combined 100% interest in SC56 to the Philippines Department of Energy ("DOE"). As a result, the carrying value of US$50.4 million was impaired in Q4 2020. The DOE acknowledged the relinquishment in February 2021 and the exit obligation terms were agreed in June 2021. Accordingly, the carrying value was formally written off in 2021.

The Group had also written off intangible exploration assets of US$5.3 million in 2021 (Note 10).

(e) The transfer relates to the Lemang PSC in Indonesia. On 6 June 2022, the final investment decision was taken following regulatory approval to award the engineering, procurement, construction and installation ("EPCI") contract which established commercial viability. The capitalised cost of US$18.9 million was transferred to development assets as disclosed in Note 22.

22. OIL AND GAS PROPERTIES

	Production assets USD'000	Development assets USD'000	Total USD'000
Cost			
As at 1 January 2021	496,992	-	496,992
Changes in asset restoration obligations (Note 35)	23,894	-	23,894
Acquisition of PenMal Assets (Note 20)	21,744	-	21,744
Additions	52,864	-	52,864*
As at 31 December 2021	**595,494**	**-**	**595,494**
Changes in asset restoration obligations (Note 35)	20,768	7	20,775
Acquisition of CWLH assets (Note 18)	41,976	-	41,976
Acquisition of 10% interest in Lemang PSC (Note 19)	-	1,414	1,414
Additions	62,319	16,619	78,938*
Written off	(3,704)	-	(3,704)**
Transfer	-	18,895	18,895
As at 31 December 2022	**716,853**	**36,935**	**753,788**
Accumulated depletion, amortisation and impairment			
As at 1 January 2021	179,316	-	179,316
Charge for the year	62,586	-	62,586
As at 31 December 2021	**241,902**	**-**	**241,902**
Charge for the year	45,288	-	45,288
Impairment	13,534	-	13,534
Written off	(3,704)	-	(3,704)**
As at 31 December 2022	**297,020**	**-**	**297,020**

	Production assets USD'000	Development assets USD'000	Total USD'000
Net book value			
As at 1 January 2021	**317,676**	**-**	**317,676**
As at 31 December 2021	**353,592**	**-**	**353,592**
As at 31 December 2022	**419,833**	**36,935**	**456,768**

* The additions in 2022 represents cash paid for the Group's capital expenditure projects. In 2021, the amount consisted of cash payments of US$51.4 million and capitalisation of depreciation of US$1.5 million associated with right-of-use assets in Australia in accordance with IAS 16, both associated with the drilling of the H6 infill well at Montara.

** The written off amount represents the fully depreciated oil and gas properties associated with the Indonesian Ogan Komering PSC of which the PSC had expired in 2018.

23. PLANT AND EQUIPMENT

	Computer equipment USD'000	Fixtures and fittings USD'000	Materials and spares USD'000	Total USD'000
Cost				
As at 1 January 2021	3,104	1,508	-	4,612
Additions	450	232	-	682
Written off	-	(169)	-	(169)
Transfer	-	-	7,209	7,209*
As at 31 December 2021	**3,554**	**1,571**	**7,209**	**12,334**
Additions	204	152	-	356
Written off	(313)	(14)	-	(327)
Transfer	-	-	(1,173)	(1,173)*
As at 31 December 2022	**3,445**	**1,709**	**6,036**	**11,190**
Accumulated depreciation				
As at 1 January 2021	1,657	1,303	-	2,960
Charge for the year	302	206	-	508
Written off	-	(97)	-	(97)
As at 31 December 2021	**1,959**	**1,412**	**-**	**3,371**
Charge for the year	450	166	-	616
Written off	(101)	(14)	-	(115)
As at 31 December 2022	**2,308**	**1,564**	**-**	**3,872**
Net book value				
As at 1 January 2021	**1,447**	**205**	**-**	**1,652**
As at 31 December 2021	**1,595**	**159**	**7,209**	**8,963**
As at 31 December 2022	**1,137**	**145**	**6,036**	**7,318**

* The transfer represents the material and spares that are not expected to be consumed within the next 12 months from the year end. The reclassification amount is net of allowance of slow moving items of US$2.7 million (2021: US$1.9 million).

24. RIGHT-OF-USE ASSETS

	Transportation and logistics USD'000	Buildings USD'000	Total USD'000
Cost			
As at 1 January 2021	42,345	3,169	45,514
Additions	1,200	1,654	2,854
As at 31 December 2021	**43,545**	**4,823**	**48,368**
Additions	6,701	655	7,356
Written off*	(4,146)	(1,835)	(5,981)
As at 31 December 2022	**46,100**	**3,643**	**49,743**
Accumulated depreciation			
As at 1 January 2021	19,938	1,903	21,841
Charge for the year	11,470*	1,205	12,675**
As at 31 December 2021	**31,408**	**3,108**	**34,516**
Charge for the year	12,224	791	13,015
Written off	(4,146)	(1,835)	(5,981)
As at 31 December 2022	**39,486**	**2,064**	**41,550**
Net book value			
As at 1 January 2021	**22,407**	**1,266**	**23,673**
As at 31 December 2021	**12,137**	**1,707**	**13,852**
As at 31 December 2022	**6,614**	**1,579**	**8,193**

* This represents the write off of expired leases.

** The amount included US$1.5 million which has been capitalised within oil and gas properties as the related right-of-use assets were used as part of the drilling of the H6 infill well at Montara (see Note 22).

Most of the Group's lease liabilities are contracts to lease assets including helicopters, a supply boat, logistic facilities for the Montara field and buildings. The average lease term is 2.8 years.

The maturity analysis of lease liabilities is presented in Note 36.

	2022 USD'000	2021 USD'000
Amount recognised in profit or loss		
Depreciation expense on right-of-use assets	13,015	11,191
Interest expense on lease liabilities	769	1,222
Expenses relating to short-term leases	16,028	63,734
Expense relating to leases of low value assets	68	81

At 31 December 2022, the Group is committed to US$3.0 million of short-term leases (2021: nil).

The total cash outflow in 2022 relate to leases was US$13.9 million (2021: US$13.0 million).

The additions to right-of-use assets during the year represent the extension of the Group's ongoing right-of-use assets, plus a two-year lease for airport services contract to replace an expired lease and a four-and-half-year lease for additional space in the Australian office building.

25. INTERESTS IN OPERATIONS

Details of the operations, of which all are in production except for 46/07 and 51 which are in the exploration stage while the Lemang PSC is in the development stage, are as follows:

Contract Area	Date of expiry	Held by	Place of operations	Group effective working interest % as at 31 December 2022	2021
Montara oilfield	Indefinite	Jadestone Energy (Eagle) Pty Ltd	Australia	100	100
Stag Oilfield	25 Aug 2039	Jadestone Energy (Australia) Pty Ltd	Australia	100	100
PM329	8 December 2031	Jadestone Energy (PM) Inc.	Malaysia	70	70
PM323	14 June 2028	Jadestone Energy (PM) Inc.	Malaysia	60	60
PM318	24 May 2034	Jadestone Energy (PM) Inc.	Malaysia	50	50
AAKBNLP	24 May 2024	Jadestone Energy (PM) Inc.	Malaysia	50	50
WA-3-L	Indefinite	Jadestone Energy (CWLH) Pty Ltd	Australia	17	-
WA-9-L	15 July 2033	Jadestone Energy (CWLH) Pty Ltd	Australia	17	-
WA-11-L	4 September 2035	Jadestone Energy (CWLH) Pty Ltd	Australia	17	-
WA-16-L	11 September 2039	Jadestone Energy (CWLH) Pty Ltd	Australia	17	-
46/07	29 Jun 2035	Mitra Energy (Vietnam Nam Du) Pte Ltd	Vietnam	100	100
51	10 Jun 2040	Mitra Energy (Vietnam Tho Chu) Pte Ltd	Vietnam	100	100
Lemang	17 Jan 2037	Jadestone Energy (Lemang) Pte Ltd	Indonesia	100	90

26. DEFERRED TAX

The following are the deferred tax liabilities and assets recognised by the Group and movements thereon.

	Australian PRRT USD'000	Malaysian PITA USD'000	Tax depreciation USD'000	Total USD'000
As at 1 January 2021	17,917	-	(56,419)	(38,502)
Charged to profit or loss (Note 16)	(3,371)	3,176	(5,246)	(5,441)
Acquisition of PenMal Assets (Note 20)	-	4,166	-	4,166
As at 31 December 2021 (Restated)*	**14,546**	**7,342**	**(61,665)**	**(39,777)**
Charged to profit or loss (Note 16)	(7,032)	(5,737)	(14,149)	(26,918)
Acquisition of CWLH Assets (Note 18)	(12,593)	-	-	(12,593)
As at 31 December 2022	**(5,079)**	**1,605**	**(75,814)**	**(79,288)**

The following is the analysis of the deferred tax balances (after offset) for financial reporting purposes:

	2022 USD'000	2021 Restated* USD'000
Deferred tax liabilities	(88,406)	(66,166)
Deferred tax assets	9,118	26,389
	(79,288)	**(39,777)**

The Group has unutilised PRRT credits of approximately US$3.5 billion (2021: US$3.4 billion) available for offset against future PRRT taxable profits in respect of the Montara field. The PRRT credits remain effective throughout the production licence of Montara. No deferred tax asset has been recognised in respect of these PRRT credits, due to management's projections that the historic accumulated PRRT net losses are larger than cumulative future expected PRRT taxable profits. As PRRT credits are utilised based on a last-in-first-out basis, the unutilised PRRT credits of approximately US$3.5 billion (2021: US$3.4 billion) is not expected to be utilised and are therefore not recognised as a deferred tax asset.

*Certain 2021 comparative information has been restated. Please refer to Note 45.

27. INVENTORIES

	2022 USD'000	2021 USD'000
Materials and spares	18,236	13,590
Less: allowance for slow moving (Note 10)	(6,334)	(3,639)
	11,902	**9,951**
Crude oil inventories	7,009	13,348
	18,911	**23,299**

The cost of inventories recognised as an expense during the year for lifted volumes, is calculated by including production costs excluding workovers, Malaysian supplementary payments and tariffs and transportation costs, plus depletion expense of oil & gas properties, and plus depreciation of right-of-use assets deployed for operational use. In 2022, this cost totalled US$263.3 million (2021: US$205.7 million).

28. TRADE AND OTHER RECEIVABLES

	2022 USD'000	2021 Restated* USD'000
Current assets		
Trade receivables	6,332	9,143
Prepayments	3,119	3,770
Other receivables and deposits	4,859	13,281
Amount due from joint arrangement partners (net)	4,268	2,203
Underlift crude oil inventories	107	1,482
GST/VAT receivables	1,683	2,699
	20,368	**32,578**
Non-current assets		
Other receivables	83,192	41,726
Prepayment	-	2,000
VAT receivables	7,398	4,774
	90,590	**48,500**
	110,958	**81,078**

Trade receivables arise from revenues generated from the Group's respective sole customer in Australia and Malaysia. The average credit period is 30 days (2021: 30 days). All outstanding receivables as at 31 December 2022 and 2021 have been recovered in full in 2023 and 2022, respectively.

*Certain 2021 comparative information has been restated. Please refer to Note 45.

Other receivables under the current asset in 2021 consisted of insurance claim receivable of US$10.3 million on the well control claim for the Skua 11 well workovers. The cash amount was received in June 2022.

Amount due from joint arrangement partners of US$4.3 million (2021: US$1.8 million) represents cash calls receivable from the Malaysian joint arrangement partner, net of joint arrangement expenditures. The amount is unsecured, with a credit period of 15 days. A notice of default will be served to the joint arrangement partner if the credit period is exceeded, which will become effective seven days after service of such notice if the outstanding amount remains unpaid. Interest of 3% per annum will be imposed on the outstanding amount, starting from the effective date of default. The outstanding receivable was received in 2023.

The amount due from joint arrangement partners in 2021 also included a cash call receivable of US$0.4 million due from the Indonesian joint arrangement partner, Hexindo. The amount was unsecured, with a credit period of 7 days. A notice of default will be served to the joint arrangement partner if the credit period is exceeded, which will become effective seven days after service of such notice if the outstanding amount remains unpaid. An interest at SONIA[1] plus 3% per annum will be imposed on the outstanding amount, starting from the effective date of default. Following the completion of the 10% interest acquisition, the Group released Hexindo from the unpaid cash call receivable (Note 19).

Non-current other receivables represent the accumulated cess payment paid to the Malaysian regulator for the operated licences and an abandonment trust fund set up following the acquisition of the CWLH Assets. The Malaysian PSCs require upstream operators to contribute periodic cess payments to a cess abandonment fund throughout the production life of the upstream oil and gas assets, while the abandonment trust fund was set up as part of the acquisition of the CWLH Assets. The payments made were to ensure there are sufficient funds available for decommissioning expenditures activities at the end of the fields' life. The cess payment amount is assessed based on the estimated future decommissioning expenditures.

The non-current VAT receivables are associated with the Lemang PSC. It is classified as a non-current asset as the recovery of the VAT receivables is dependent on the share of revenue entitlement by the Indonesian government after the commencement of gas production, which is expected to occur in the first half of 2024.

There are no trade receivables older than 30 days. The credit risk associated with the trade receivables is disclosed in Note 39.

29. CASH AND BANK BALANCES

	2022 USD'000	2021 Reclassified* USD'000
Cash and bank balances, representing cash and cash equivalents in the consolidated statement of cash flows, presented as:		
Non-current	676	852
Current	122,653	117,013
	123,329	**117,865**

*Certain 2021 comparative information has been reclassified between line items. Please refer to Note 45.

[1] Sterling Overnight Index Average rate

The non-current cash and cash equivalents represents the restricted cash balance of US$0.4 million (2021: US$0.4 million) and US$0.3 million (2021: US$0.5 million) in relation to a deposit placed for bank guarantee with respect to the PenMal Assets and Australian office building, respectively. The bank guarantees are expected to be in place for a period of more than twelve months. Accordingly, reclassification was made to 2021 comparatives to classify the amount as a non-current asset as disclosed in Note 45, as a result of the the April 2022 IFRIC Agenda item "Demand Deposits with Restrictions on Use arising from a Contract with a Third Party (IAS 7 *Statement of Cash Flows*).

In 2021, for the purpose of the consolidated statement of cash flows, the transfer from debt service reserve account represented a restricted cash balance of US$7.4 million which was deposited into a debt service reserve account ("DSRA") under the Group's previous reserve based lending arrangement. The DSRA was released on 31 March 2021, upon the repayment of the final balance outstanding on the loan. The Group also had a restricted cash balance in 2020 of US$1.0 million, placed with the Indonesian regulator in relation to a joint study agreement ("JSA"). The amount was released to the Group during Q3 2021 upon the completion of the JSA.

30. SHARE CAPITAL AND SHARE PREMIUM ACCOUNT

	No. of shares	Share capital USD'000	Share premium account USD'000
Issued and fully paid			
As at 1 January 2021	461,842,811	466,979	-
Issued during the year	3,238,427	766	201
Capital reduction, at £0.499 each	-	(467,387)	-
As at 31 December 2021 (Reclassified)*	**465,081,238**	**358**	**201**
Issued during the year	1,446,108	2	782
Share repurchases	(18,173,683)	(21)	-
As at 31 December 2022	**448,363,663**	**339**	**983**

On 4 May 2021, the High Court of Justice, Business and Property Court, Companies Court in England and Wales approved the reduction of share capital of the Company pursuant to section 648 of the Act by cancelling the paid-up capital of the Company to the extent of 49.9 pence on each ordinary share of £0.50 in the issued share capital of the Company. The effective date of the capital reduction was 6 May 2021.

On 2 August 2022, the Company announced the launch of a share buyback programme (the "Programme") in accordance with the authority granted by the shareholders at the Company's annual general meeting on 30 June 2022. The maximum amount of the Programme was US$25.0 million, and the Programme will not exceed 46,574,528 ordinary shares.

As at 31 December 2022, the Company had acquired 18.2 million shares at a weighted average cost of £0.76 per share, resulting in an accumulated total expenditure of US$16.1 million.

During the year, employee share options of 1,446,108 were exercised and issued at an average price of GB£ 0.42 per share (2021: 3,238,427; GB£0.33 per share).

The Company has one class of ordinary share. Fully paid ordinary shares with par value of £0.001 per share carry one vote per share without restriction, and carry a right to dividends as and when declared by the Company.

*Certain 2021 comparative information has been reclassified between line items. Please refer to Note 45.

31. DIVIDENDS

The parent company has sufficient distributable reserves to declare dividends. The distributable reserves were created at the Company level through the reduction of share capital of the Company in May 2021 (Note 8 of Company level financial statements). The dividends declared were in compliance with the Act.

On 20 September 2022, the Directors declared a 2022 interim dividend of 0.65 US cents/share, equivalent to a total distribution of US$3.0 million. The dividend was paid on 11 October 2022.

On 6 June 2022, the Directors recommended a final 2021 dividend of 1.34 US cents/share, equivalent to a total distribution of US$6.2 million, or US$9.0 million in respect of total 2021 dividends. The dividend was approved by shareholders on 30 June 2022 and paid on 5 July 2022.

On 9 September 2021, the Directors declared a 2021 interim dividend of 0.59 US cents/share, equivalent to a total distribution of US$2.8 million. The dividend was paid on 1 October 2021.

On 11 June 2021, the Directors declared the second interim 2020 dividend of 1.08 US cents/share, equivalent to a total distribution of US$5.0 million, or US$7.5 million in respect of total 2020 dividends. The dividend was paid on 30 June 2021.

32. MERGER RESERVE

The merger reserve arose from the difference between the carrying value and the nominal value of the shares of the Company, following completion of the internal reorganisation in 2021.

33. SHARE-BASED PAYMENTS RESERVE

The total expense arising from share-based payments of US$1.0 million (2021: US$1.0 million) was recognised as 'administrative staff costs' (Note 7) in profit or loss for the year ended 31 December 2022.

On 15 May 2019, the Company adopted, as approved by the shareholders, the amended and restated stock option plan, the performance share plan, and the restricted share plan (together, the "LTI Plans"), which establishes a rolling number of shares issuable under the LTI Plans up to a maximum of 10% of the Company's issued and outstanding ordinary shares at any given time. Options under the stock option plan will be exercisable over periods of up to 10 years as determined by the Board.

33.1 Share options

Management has applied the Black-Scholes option-pricing model, with the following assumptions, was used to estimate the fair value of the options at the date of grant:

	Options granted on	
	9 March 2022	**18 March 2021**
Risk-free rate	1.34% to 1.38%	0.49% to 0.61%
Expected life	5.5 to 6.5 years	5.5 to 6.5 years
Expected volatility[1]	63.0% to 66.7%	65.2% to 67.6%
Share price	GB£ 1.01	GB£ 0.65
Exercise price	GB£ 0.92	GB£ 0.77
Expected dividends	1.96%	1.79%

[1] Expected volatility was determined by calculating the average historical volatility of the daily share price returns over a period commensurate with the expected

life of the awards for a group of ten peer companies.

33.2 Performance shares

The performance measures for performance shares incorporate both a relative and absolute total shareholder return ("TSR") calculation on a 70:30 basis to compare performance vs. peers (relative TSR) and to ensure alignment with shareholders (absolute TSR).

Relative TSR: measured against the TSR of peer companies; the size of the pay out is based on Jadestone's ranking against the TSR outcomes of peer companies.

Absolute TSR: share price target plus dividend to be set at the start of the performance period and assessed annually; the threshold share price plus dividend has to be equal to or greater than a 10% increase in absolute terms to earn any pay out at all, and must be 25% or greater for target pay out.

A Monte Carlo simulation model was used by an external specialist, with the following assumptions to estimate the fair value of the performance shares at the date of grant:

	Performance shares granted on	
	9 March 2022	**18 March 2021**
Risk-free rate	1.39%	0.06%
Expected volatility[1]	53.1%	51.4%
Share price	GB£ 1.01	GB£ 0.77
Exercise price	N/A	N/A
Expected dividends	1.71%	2.64%
Post-vesting withdrawal date	N/A	N/A
Early exercise assumption	N/A	N/A

33.3 Restricted shares

Restricted shares are granted to certain senior management personnel as an alternative to cash under exceptional circumstances and to provide greater alignment with shareholder objectives. These are shares that vest three years after grant, assuming the employee has not left the Group. They are not eligible for dividends prior to vesting.

The following assumptions were used to estimate the fair value of the restricted shares at the date of grant, discounting back from the date they will vest and excluding the value of dividends during the intervening period:

	Restricted shares granted on		
	22 August 2022	**9 March 2022**	**18 March 2021**
Risk-free rate	1.73%	1.39%	0.08%
Share price	GB£ 0.90	GB£ 1.01	GB£ 0.77
Expected dividends	1.73%	1.71%	2.64%

[1] Expected volatility was determined by calculating Jadestone's average historical volatility of each trading day's log growth of TSR over a

period between the grant date and the end of the performance period.

The following table summarises the options/shares under the LTI plans outstanding and exercisable as at 31 December 2022:

			Shares Options			
	Performance shares	Restricted shares	Number of options	Weighted average exercise price GB£	Weighted average remaining contract life	Number of options exercisable
As at 1 January 2021	**683,200**	**101,063**	**25,192,842**	**0.40**	**7.78**	**12,212,827**
New options/share awards issued	1,136,512	50,570	2,852,631	0.77	9.21	-
Vested during the year	-	-	-	0.42	6.92	3,776,672
Accelerated vesting during the year	-	-	198,687	0.55	8.39	198,687
Exercised during the year	-	-	(3,238,427)	0.33	-	(3,238,427)
Cancelled during the year	(332,819)	-	(3,690,244)	0.46	-	(1,539,905)
As at 31 December 2021	**1,486,893**	**151,633**	**21,315,489**	**0.45**	**7.16**	**11,409,854**
New options/share awards issued	1,385,013	293,655	1,023,561	0.92	9.19	-
Vested during the year	-	-	-	0.50	6.27	2,010,007
Accelerated vesting during the year	-	-	1,354,702	0.46	6.45	1,354,702
Exercised during the year	-	-	(1,446,108)	0.42	-	(1,446,108)
Cancelled during the year	(147,906)	-	(120,854)	0.50	-	(891,270)
As at 31 December 2022	**2,724,000**	**445,288**	**22,176,790**	**0.48**	**6.33**	**12,437,185**

	Number of options	Range of exercise price GB£	Weighted average exercise price GB£	Weighted average remaining contract life
Share options exercisable as at 31 December 2021	11,409,854	0.26 - 0.99	0.38	6.18
Share options exercisable as at 31 December 2022	12,437,185	0.26 - 0.99	0.41	5.46

34. CAPITAL REDEMPTION RESERVE

The capital redemption reserve arose from the Programme launched by the Company in August 2022. It represents the par value of the shares purchased and cancelled by the Company under the Programme (Note 30).

35. PROVISIONS

	Asset restoration obligations (a) USD'000	Contingent payments (b) USD'000	Employees benefits (c) USD'000	Others USD'000	Total USD'000
As at 1 January 2021	283,749	4,436	896	-	289,081
Charged to profit or loss	-	-	-	202	202
Acquisition of PenMal Assets (Note 20)	91,552	4,305	-	-	95,857
Accretion expense (Note 14)	5,921	-	-	-	5,921
Changes in discount rate assumptions (Notes 21, 22 and 28)	23,179	-	-	-	23,179
Payment/Utilised	-	(3,000)	(52)	-	(3,052)
Fair value adjustment (Note 14)	-	438	-	-	438
Reversal (Note 13)	-	-	-	-	-
As at 31 December 2021 (Reclassified)*	**404,401**	**6,179**	**844**	**202**	**411,626**
Charged/(Credited) to profit or loss	-	-	122	(202)	(80)
Acquisition of CWLH Assets (Note 18)	60,158	1,940	-	-	62,098
Acquisition of 10% interest in Lemang PSC (Note 19)	337	-	-	-	337
Accretion expense (Note 14)	8,314	-	-	-	8,314
Changes in discount rate assumptions (Note 22)	20,775	-	-	-	20,775
Payment/Utilised	-	-	(81)	-	(81)
Change in provision (Note 10)	-	7,333	-	-	7,333
Fair value adjustment – Lemang PSC (Note 14)	-	349	-	-	349
Fair value adjustment – PenMal Assets (Note 14)	-	1,571	-	-	1,571
Reclassification	-	(3,000)	-	-	(3,000)
As at 31 December 2022	**493,985**	**14,372**	**885**	**-**	**509,242**
As at 31 December 2021 (Reclassified)*					
Current	-	-	728	202	930
Non-current	404,401	6,179	116	-	410,696
	404,401	**6,179**	**844**	**202**	**411,626**
As at 31 December 2022					
Current	-	-	703	-	703
Non-current	493,985	14,372	182	-	508,539
	493,985	**14,372**	**885**	**-**	**509,242**

*Certain 2021 comparative information has been reclassified between line items. Please refer to Note 45.

(a) The Group's asset restoration obligations ("ARO") comprise the future estimated costs to decommission each of the Montara, Stag, Lemang PSC, PenMal Assets and CWLH Assets.

The carrying value of the provision represents the discounted present value of the estimated future costs. Current estimated costs of the ARO for each of the Montara, Stag, Lemang PSC, PenMal Assets and CWLH Assets have been escalated to the estimated date at which the expenditure would be incurred, at an assumed blended inflation rate. The estimates for each asset are a blend of assumed US and respective local inflation rates to reflect the underlying mix of US dollar and respective local dollar denominated expenditures. The present value of the future estimated ARO for each of the Montara, Stag, Lemang PSC, PenMal Assets and CWLH Assets has then been calculated based on a blended risk-free rate. The base estimate ARO for Montara, Stag, Lemang PSC and PenMal Assets remains largely unchanged from 2021. The ARO of CWLH Assets was assessed in 2022, based on its share of the future estimated decommissioning expenditure at the end of field life according to the Group's 16.67% non-operating working interest. The blended inflation rates and risk-free rates used, plus the estimated decommissioning year of each asset are as follows:

		Blended inflation rate		Blended risk-free rate		Estimated decommissioning
No.	**Asset**	**2022**	**2021**	**2022**	**2021**	**year**
1.	Montara	3.01%	2.06%	3.97%	1.77%	2033
2.	Stag	2.62%	2.12%	4.01%	1.91%	2036
3.	Lemang PSC	2.93%	2.82%	6.43%	5.96%	2036
4.	PenMal Assets	2.46% - 2.48%	2.05% - 2.07%	3.48% - 4.02%	2.81% - 3.24%	2024 onwards
5.	CWLH Assets	3.05%	-	3.94%	-	2032

In 2019, Jadestone Energy (Eagle) Pty Ltd, a wholly owned subsidiary of the Company entered into a deed poll with the Australian Government with regard to the requirements of maintaining sufficient financial capacity to ensure Montara's asset restoration obligations can be met when due. The deed states that the Group is required to provide a financial security in favour of the Australian Government when the aggregate remaining net after tax cash flow of the Group is 1.25 times or below the Group's estimated future decommissioning costs. On 29 March 2023, Jadestone Energy (Australia) Pty Ltd, a wholly owned subsidiary of the Company entered into a similar deed poll which required the Group to maintain sufficient financial capacity to ensure Stag's asset restoration obligations can be met when due.

Following the enactment of the Offshore Petroleum and Greenhouse Gas Storage Amendment (Titles Administration and Other Measures) Act 2021 enhancing the offshore oil and gas decommissioning framework and in conjunction with the regulatory review of the CWLH title transfer, the Group is currently in discussion with the Australian regulator to incorporate certain amendments to the deed poll in respect of the requirements of maintaining sufficient financial capacity to ensure Australian asset restoration obligations can be met when due. The Group does not expect these amendments to materially change the result of the financial capacity assessment currently contemplated under the existing deed poll.

The Malaysian and Indonesian regulators require upstream oil and gas companies to contribute to an abandonment cess fund, including making monthly cess payments, throughout the production life of the oil or gas field. The cess payment amount is assessed based on the estimated future decommissioning expenditures. The cess payment paid for non-operated licences reduces the asset restoration liability. The Malaysian abandonment cess fund only covers the decommissioning costs related to the oil and gas facilities. The Group has recognised ARO provisions for the estimated decommissioning costs of the wells in the PSCs.

An abandonment trust fund was set as part of the acquisition of the CWLH Assets to ensure there are sufficient funds available for decommissioning activities at the end of field life. The payment paid into to the trust fund is classified as non-current receivables as the amount is reclaimable by the Group in the future following the commencement of decommissioning activities.

(b) A contingent payment of US$1.4 million payable to SapuraOMV for the PenMal Assets acquisition was recognised in full at US$3.0 million at the 2022 year end as materialised and was reclassified as accrual due to the average Dated Brent price in 2022 exceeding US$70/bbl. The contingent payment was paid in January 2023.

The fair value of the contingent payments payable to Mandala Energy Lemang Pte Ltd for the Lemang PSC acquisition are valued at US$12.4 million as at 31 December 2022 (2021: US$4.8 million) for the trigger events as disclosed below. The increase in provision represents the recognition of additional contingent payments which are associated with the Saudi CP and Dated Brent prices.

No.	Trigger event	Consideration	Management's rationale
1.	First gas date	US$5.0 million	This contingent payment is virtually certain as it will be payable when gas production in the Lemang PSC is commenced.
2.	The accumulated VAT receivables reimbursements which are attributable to the unbilled VAT in the Lemang Block as at the Closing Date, exceeding an aggregate amount of US$6.7 million on a gross basis	US$0.7 million	Management estimated that the accumulated receipts of VAT reimbursements received will exceed US$6.7 million on a gross basis.
3.	First gas date on or before 31 March 2023	US$3.0 million	It is unlikely that the first gas date will be on or before 31 March 2023.
4.	Total actual Akatara Gas Project "close out" costs set out in the AFE(s) approved pursuant to a joint audit by SKK MIGAS and BPKP is less than, or within 2% of the "close out" development costs set out in the approved revised plan of development for the Akatara Gas Project	US$3.0 million	The Akatara Gas Project has not been sanctioned as at year end due to ongoing preparation of project approval documentation. It is unknown if the future close out costs will be less than or within 2% of the budgeted amount and it is unable to be reliably measured as at year end.
5.	The average Saudi CP in the first year of operation is higher than US$620/MT	US$3.0 million	The average Saudi CP is expected to be above US$620/MT in 2024, with the first gas is anticipated to be in H1 2024. The contingent payment will be due for payment within 15 business days of the occurrence of the trigger event if it falls due.
6.	The average Saudi CP in the second year of operation is higher than US$620/MT	US$2.0 million	The average Saudi CP is expected to be above US$620/MT in 2025, the second year of production. The contingent payment will be due for payment within 15 business days of the occurrence of the trigger event if it falls due.
7.	The average Dated Brent price in the first year of operation is higher than US$80/bbl	US$2.5 million	The average Dated Brent price is expected to be above US$80/bbl in 2024, with the first gas is anticipated to be in H1 2024. The contingent payment will be due for payment within 15 business days of the occurrence of the trigger event if it falls due.

No.	Trigger event	Consideration	Management's rationale
8.	The average Dated Brent price in the second year of operation is higher than US$80/bbl	US$1.5 million	The average Dated Brent price is expected to be above US$80/bbl in 2025, the second year of production. The contingent payment will be due for payment within 15 business days of the occurrence of the trigger event if it falls due.
9.	A plan of development for the development of a new discovery made, as a result of the remaining exploration well commitment under the PSC, is approved by the relevant government entity.	US$3.0 million	There are no prospects or leads presently selected for the exploration well commitment. As at year end, it is not probable that this contingent consideration trigger will be met.
10.	The plan of development described in item 9 above is approved by the relevant government entity and is based on reserves of no less than 8.4mm barrels (on a gross basis).	US$8.0 million	There are no prospects or leads presently selected for the exploration well commitment. As at year end, it is not probable that this contingent consideration trigger will be met.

(c) Included in the provision for employee benefits is provision for long service leave which is payable to employees on a pro-rata basis after 7 years of employment and is due in full after 10 years of employment.

36. LEASE LIABILITIES

	2022 USD'000	2021 USD'000
Presented as:		
Non-current	2,880	4,504
Current	6,227	11,161
	9,107	**15,665**
Maturity analysis of lease liabilities based on undiscounted gross cash flows:		
Year 1	6,649	12,247
Year 2	2,261	3,440
Year 3	426	209
Year 4	334	221
Year 5	-	233
Future interest charge	(563)	(685)
	9,107	**15,665**

The Group does not face a significant liquidity risk with regards to its lease liabilities. Lease liabilities are monitored within the Group's treasury function.

37. RECONCILIATION OF LIABILITIES ARISING FROM FINANCING ACTIVITIES

The table below details changes in the Group's liabilities arising from financing activities, including both cash and non-cash changes. Liabilities arising from financing activities are those for which cash flows were, or future cash flows will be, classified in the Group's consolidated statement of cash flows, as cash flows from financing activities.

The cash flows represent the repayment of borrowings and lease liabilities, in the consolidated statement of cash flows.

	Reserved based lending facility USD'000	Lease liabilities USD'000
As at 1 January 2021	7,296	25,783
Financing cash flows	(7,296)	(12,972)
New lease liabilities	-	2,854
Interest paid	150	(1,222)
Non-cash changes - interest	(150)	1,222
As at 31 December 2021	**-**	**15,665**
Financing cash flows	-	(13,914)
New lease liabilities	-	7,356
Interest paid	-	769
Non-cash changes - interest	-	(769)
As at 31 December 2022	**-**	**9,107**

38. TRADE AND OTHER PAYABLES

	2022 USD'000	2021 Reclassified* USD'000
Trade payables	13,606	26,847
Other payables	8,643	7,627
Accruals	36,757	30,716
Contingent payments	5,000	3,000
Malaysian supplementary payment payables	855	1,907
Amount due to joint arrangement partner	1,269	-
Overlift crude oil inventories	7,357	-
GST/VAT payables	265	10
	73,752	**70,107**

Trade payables, other payables and accruals principally comprise amounts outstanding for trade and non-trade related purchases and ongoing costs. The average credit period taken for purchases is 30 days (2021: 30 days). For most suppliers, no interest is charged on the payables in the first 30 days from the date of invoice. Thereafter, interest may be charged on outstanding balances at varying rates of interest. The Group has financial risk management policies in place to ensure that all payables are settled within the pre-agreed credit terms.

*Certain 2021 comparative information has been restated and reclassified between line items. Please refer to Note 45.

Contingent payments in the current year consist of US$3.0 million payable to SapuraOMV, being the second contingent payment arose from the acquisition of the PenMal Assets (Notes 20 and 35). The payment was made in January 2023. The Group is obliged to pay to a contingent payment of US$2.0 million to BP which arose from the acquisition of the CWLH Assets (Note 18) as the annual average Brent crude price in 2022 exceeded US$50/bbl. The payment was made in January 2023. The contingent payment in the prior year represented the first contingent payment of US$3.0 million payable to SapuraOMV as the annual average Brent crude price in 2021 exceeded US$65/bbl. The payment was made in January 2022.

The overlift crude oil inventories represent entitlement imbalances at 2022 year end of 205,510 bbls and 31,076 bbls at the CWLH Assets and PenMal Assets, respectively. The overlift liabilities are measured at cost of US$32.92/bbl and US$19.07/bbl for both assets, respectively. The overlift position at 2022 year end will unwind in 2023 based on the subsequent net productions entitled to the Group.

39. FINANCIAL INSTRUMENTS, FINANCIAL RISKS AND CAPITAL MANAGEMENT

Financial assets and liabilities

Current assets and liabilities
Management considers that due to the short-term nature of the Group's current assets and liabilities, the carrying amounts equate to their fair value.

Non-current assets and liabilities
The carrying amount of non-current assets and liabilities approximates their fair values due to the carrying amount representing the actual cash paid.

	2022 USD'000	2021 Restated* USD'000
Financial assets		
At amortised cost		
Trade and other receivables, excluding prepayments, GST/VAT receivables and underlift crude oil inventories	98,651	66,353
Cash and bank balances	123,329	117,865
	221,980	**184,218**
Financial liabilities		
At amortised cost		
Trade and other payables, excluding GST/VAT payables and overlift crude oil inventories	61,130	70,097
Lease liabilities	9,107	15,665
Contingent consideration for Lemang PSC acquisition	12,432	4,750
Contingent consideration for CWLH Assets acquisition	3,940	-
Contingent consideration for PenMal Assets acquisition	3,000	1,429
	89,609	**91,941**

*Certain 2021 comparative information has been restated and reclassified between line items. Please refer to Note 45.

Fair values are based on management's best estimates, after consideration of current market conditions. The estimates are subjective and involve judgment, and as such may deviate from the amounts that the Group realises in actual market transactions.

Commodity price risk

The Group's earnings are affected by changes in oil prices. The Group manages this risk by monitoring oil prices and potentially entering into commodity hedges against fluctuations in oil prices if and when considered appropriate. The Group does not enter into speculative hedges. The Group may enter into hedging arrangements as required under a reserves based lending facility. The Group had hedging in place associated with its RBL which were fully settled in 2021.

There was no hedge contract in place nor entered into by the Group in 2022.

Montara

In December 2020, the Group entered into a commodity swap arrangement to hedge 31% of its planned production volumes from January to March 2021, to provide downside oil price protection. The swap price was set at US$49/bbl.

On 16 February 2021, the Group entered into a commodity swap arrangement to further hedge 31% of its planned production volumes from April to June 2021. The swap price was set at US$61.40/bbl.

Foreign currency risk

Foreign currency risk is the risk that a variation in exchange rates between United States Dollars ("US Dollar") and foreign currencies will affect the fair value or future cash flows of the Group's financial assets or liabilities presented in the consolidated statement of financial position as at year end.

Cash and bank balances are generally held in the currency of likely future expenditures to minimise the impact of currency fluctuations. It is the Group's normal practice to hold the majority of funds in US Dollars, in order to match the Group's revenue and expenditures.

In addition to US Dollar, the Group transacts in various currencies, including Australian Dollar, Malaysian Ringgit, Vietnamese Dong, Indonesian Rupiah, Singapore Dollar, New Zealand Dollar and British Pound Sterling.

Foreign currency sensitivity

Material foreign denominated balances were as follows:

	2022 USD'000	2021 USD'000
Cash and bank balances		
Australian Dollars	11,086	6,027
Malaysian Ringgit	5,336	4,622
Trade and other receivables		
Australian Dollars	4,789	2,706
Malaysian Ringgit	42,392	41,774
Trade and other payables		
Australian Dollars	32,767	43,219
Malaysian Ringgit	12,422	15,094

A strengthening/weakening of the Australian dollar and Malaysian Ringgit by 10%, against the functional currency of the Group, is estimated to result in the net carrying amount of Group's financial assets and financial liabilities as at year end increasing/decreasing by approximately US$1.8 million (2021: decreasing/increasing by US$0.4 million), and which would be credited/charged (2021: charged/credited) to the consolidated statement of profit or loss.

Interest rate risk

The Group's interest rate exposure arises from some of its cash and bank balances. The Group's other financial instruments are non-interest bearing or fixed rate, and are therefore not subject to interest rate risk.

The Group holds some of its cash in interest bearing accounts and short-term deposits. Interest rates currently received are at relatively low levels. Accordingly, a downward interest rate movement would not cause significant exposure to the Group.

Credit risk

Credit risk represents the financial loss that the Group would suffer if a counterparty in a transaction fails to meet its obligations in accordance with the agreed terms.

The Group actively manages its exposure to credit risk, granting credit limits consistent with the financial strength of the Group's counterparties and respective sole customer in Australia and Malaysia, requiring financial assurances as deemed necessary, reducing the amount and duration of credit exposures, and close monitoring of relevant accounts.

The Group trades only with recognised, creditworthy third parties.

The Group's current credit risk grading framework comprises the following categories:

Category	**Description**	**Basis for recognising expected credit losses ("ECL")**
Performing	The counterparty has a low risk of default and does not have any past due amounts.	12-month ECL
Doubtful	Amount is > 30 days past due or there has been a significant increase in credit risk since initial recognition.	Lifetime ECL – not credit-impaired
In default	Amount is > 90 days past due or there is evidence indicating the asset is credit-impaired.	Lifetime ECL – credit-impaired
Write-off	There is evidence indicating that the debtor is in severe financial difficulty and the Group has no realistic prospect of recovery.	Amount is written off

The table below details the credit quality of the Group's financial assets and other items, as well as maximum exposure to credit risk by credit risk rating grades:

	Note	External credit rating	Internal credit rating	12-month ("12m") or lifetime ECL	Gross carrying amount [(i)] USD'000	Loss allowance USD'000	Net carrying amount USD'000
2022							
Cash and bank balances	29	n.a	Performing	12m ECL	123,329	-*	123,329
Trade receivables	28	n.a	(i)	Lifetime ECL	6,332	-*	6,332
Other receivables and deposits	28	n.a	Performing	12m ECL	4,859	-*	4,859
Amount due from joint arrangement partners (net)	28	n.a	Performing	12m ECL	4,268	-*	4,268
Non-current other receivables	28	n.a	Performing	12m ECL	83,192	-*	83,192
2021							
Cash and bank balances	29	n.a	Performing	12m ECL	117,865	-*	117,865
Trade receivables	28	n.a	(i)	Lifetime ECL	9,143	-*	9,143
Other receivables	28	n.a	Performing	12m ECL	13,281	-*	13,281
Amount due from joint arrangement partners (net)	28	n.a	Performing	12m ECL	2,203	-*	2,203
Non-current other receivables	28	n.a	Performing	12m ECL	41,726	-*	41,726

* The amount is negligible.

(i) For trade receivables, the Group has applied the simplified approach in IFRS 9 to measure the loss allowance at lifetime ECL. The Group determines the expected credit losses on these items by using specific identification, estimated based on historical credit loss experience based on the past due status of the debtors, adjusted as appropriate to reflect current conditions and estimates of future economic conditions. Accordingly, the credit risk profile of these assets is presented based on their past due status in terms of specific identification.

As at 31 December 2022, total trade receivables amounted to US$6.3 million (2021: US$9.1 million). The balance in 2022 and 2021 had been fully recovered in 2023 and 2022, respectively.

The concentration of credit risk relates to the Group's single customer with respect to oil sales in Australia, and a different single customer for oil and gas sales in Malaysia. Both customers have an A2 credit rating (Moody's). All trade receivables are generally settled 30 days after sale date. In the event that an invoice is issued on a provisional basis, the final reconciliation is paid within 3 to 14 days from the issuance of the final invoice, largely mitigating any credit risk.

The Group recognises lifetime ECL for trade receivables. The ECL on these financial assets are estimated based on days past due, by applying a percentage of expected non-recoveries for each group of receivables. As at year end, ECL from trade receivables are expected to be insignificant.

The Group measures the loss allowance for other receivables and amount due from joint arrangement partners at an amount equal to 12-months ECL, as there is no significant increase in credit risk since initial recognition. ECL for other receivables are expected to be insignificant.

The credit risk on cash and bank balances is limited because counterparties are banks with high credit ratings assigned by international credit rating agencies. The banks are also regulated locally, and with no history of default.

The maximum credit risk exposure relating to financial assets is represented by their carrying value as at the reporting date.

Liquidity risk

Liquidity risk is the risk that the Group will not be able to meet all of its financial obligations as they become due. This includes the risk that the Group cannot generate sufficient cash flow from producing assets, or is unable to raise further capital in order to meet its obligations.

The Group manages its liquidity risk by optimising the positive free cash flow from its producing assets, on-going cost reduction initiatives, merger and acquisition strategies, bank balances on hand and in case appropriate, lending.

The Group's net profit after tax for the year was US$8.5 million (2021: loss after tax of US$17.1 million). Operating cash flows before movements in working capital and net cash generated from operating activities for the year ended 31 December 2022 was US$158.1 million and US$121.2 million (2021: US$91.2 million and US$103.6 million) respectively. The Group's net current assets remained positive at US$72.0 million as at 31 December 2022 (2021: US$73.7 million).

The Group continues to make good progress on the RBL workstreams, with one international bank credit approved and three others in the credit approval process, with signing of the RBL facility agreement targeted for May 2023. Once signed, the RBL is expected to close shortly thereafter once all customary conditions precedent are satisfied. It is expected that approval from NOPTA of the transfer of titles relating to the acquisition for the CWLH fields interest will be required prior to drawing down the RBL.

The Directors have a high degree of confidence that the RBL facility agreement will be entered into by late May 2023. In the event that it is not, a third-party non-dilutive offer of funding has been received, which in combination with the Interim Facility, would provide sufficient liquidity to protect key capital and operating expenditures.

All these factors have been considered in the Group's near and longer term cash projections. For the purposes of the Group's going concern assessment, cash projections for the period from 1 April 2023 to 31 December 2024, the 'going concern period', have been reviewed and the Directors have reasonable expectation that the Group has adequate resources to continue in operational existence for the going concern period.

Non-derivative financial liabilities

The following table details the expected contractual maturity for non-derivative financial liabilities with agreed repayment periods. The table below is based on the undiscounted contractual maturities of the financial liabilities, including interest, that will be paid on those liabilities, except where the Group anticipates that the cash flow will occur in a different period. The adjustment column represents the estimated future cash flows attributable to the instrument included in the maturity analysis, which are not included in the carrying amount of the financial liabilities on the consolidated statement of financial position, namely interest expense.

	Weighted average effective interest rate %	On demand or within 1 year USD'000	Within 2 to 5 years USD'000	More than 5 years USD'000	Adjustments USD'000	Total USD'000
2022						
Non-interest bearing						
Trade and other payables, excluding contingent payments, GST/VAT payables and overlift crude oil inventories	-	61,130	-	-	-	61,130
Contingent consideration for Lemang PSC acquisition	-	-	12,432	-	-	12,432
Contingent consideration for CWLH Assets acquisition	-	2,000	1,940	-	-	3,940
Contingent consideration for PenMal Assets acquisition	-	3,000	-	-	-	3,000
Fixed interest rate instruments	-					
Lease liabilities	6.031	6,649	3,021	-	(563)	9,107
		72,779	**17,393**	**-**	**(563)**	**89,609**
2021 (Reclassified)*						
Non-interest bearing						
Trade and other payables, excluding contingent payments, GST/VAT payables	-	70,097	-	-	-	70,097
Contingent consideration for Lemang PSC acquisition	-	-	4,750	-	-	4,750
Fixed interest rate instruments	-	-	1,429	-	-	1,429
Lease liabilities						
Variable interest rate instruments	5.847	12,247	4,103	-	(685)	15,665
		81,327	**10,282**	**-**	**(685)**	**91,941**

*Certain 2021 comparative information has been reclassified between line items. Please refer to Note 45.

Non-derivative financial assets

The following table details the expected maturity for non-derivative financial assets. The inclusion of information on non-derivative financial assets assists in understanding the Group's liquidity position and phasing of net assets and liabilities, as the Group's liquidity risk is managed on a net asset and liability basis. The table is based on the undiscounted contractual maturities of the financial assets, including interest that will be earned on those assets, except where the Group anticipates that the cash flow will occur in a different period. The adjustment column represents the estimated future cash flows attributable to the instrument included in the maturity analysis, which are not included in the carrying amount of the financial assets on the consolidated statement of financial position, namely interest income.

	Weighted average effective interest rate %	On demand or within 1 year USD'000	Within 2 to 5 years USD'000	More than 5 years USD'000	Adjustments USD'000	Total USD'000
2022						
Non-interest bearing						
Trade and other receivables, excluding prepayments, GST/VAT receivables and underlift crude oil inventories	-	15,459	83,192	-	-	98,651
Variable interest rate instruments						
Cash and bank balances	-*	122,653	676	-	-*	123,329
		138,112	**83,868**	**-**	**-***	**221,980**
2021						
Non-interest bearing						
Trade and other receivables, excluding prepayments, GST/VAT receivables and underlift crude oil inventories	-	24,627	41,726		-	66,353
Variable interest rate instruments						
Cash and bank balances	-*	117,013	852	-	-*	117,865
		141,640	**42,578**		**-***	**184,218**

* The effect of interest is not material.

Capital management

The Group manages its capital structure and makes adjustments to it, based on funding requirements of the Group combined with sources of funding available to the Group, in order to support the acquisition, exploration and development of resource properties and the ongoing (investment in) operations of its producing assets. Given the nature of the Group's activities, the Board of Directors works with management to ensure that capital is managed effectively, and the business has a sustainable future.

The capital structure of the Group represents the equity of the Group, comprising share capital, merger reserve, share-based payment reserve and capital redemption reserve, as disclosed in Notes 30, 32, 33 and 34, respectively.

To carry-out planned asset acquisitions, exploration and development, and to pay for administrative costs, the Group may utilise excess cash generated from its ongoing operations and may utilise its existing working capital, position and will work to raise additional debt and/or equity funding should that be necessary.

Management reviews its capital management approach on an ongoing basis and believes that this approach, given the relative size of the Group, is reasonable. There were no changes in the Group's approach to capital management during the year ended 31 December 2022. The Group is not subject to externally imposed capital requirements.

	2022 USD'000	2021 USD'000
Cash and cash equivalents, representing net cash	**123,329**	**117,865**

The Group's overall strategy towards its capital structure remained unchanged from 2021.

Fair value measurements

The Group discloses fair value measurements by level of the following fair value measurement hierarchy:

i. Quoted prices (unadjusted) in active markets for identical assets or liabilities (Level 1);

ii. Inputs, other than quoted prices included within Level 1, that are observable for the asset or liability, either directly or indirectly (Level 2); and

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

Financial assets/financial liabilities	Fair value (USD'000) as at 2022 Assets	2022 Liabilities	2021 Assets	2021 Liabilities	Fair value hierarchy	Valuation technique(s) and key input(s)	Significant unobservable input(s)	Relationship of unobservable inputs to fair value
Others - contingent consideration from Lemang PSC acquisition								
1) Contingent consideration (Note 35)	-	12,432	-	4,750	Levels 1 and 3	Based on the nature and the likelihood of the occurrence of the trigger events. Fair value is estimated, taking into consideration the estimated future gas production schedule (Q1 2024), forecasted Dated Brent oil prices of US$86.83/bbl in 2024 and US$82.23/bbl in 2025 and Saudi CP prices of US$714.35/MT in 2024 and US$676.50 /MT in 2025, as well as the effect of the time value of money.	Gas production schedule could be deferred depending on the on-going progress of the development activities. Expected future oil price volatility is based on an analysis of Dated Brent oil prices and Saudi CP prices movements.	A change in gas production schedule or significant decrease in Dated Brent oil prices and Saudi CP prices in the future would result to the reversal of the contingent payments recognised.

A one year deferral to the estimated gas production date would decrease the liability by US$0.4 million.

Financial assets/financial liabilities	Fair value (USD'000) as at 2022 Assets	2022 Liabilities	2021 Assets	2021 Liabilities	Fair value hierarchy	Valuation technique(s) and key input(s)	Significant unobservable input(s)	Relationship of unobservable inputs to fair value
Others - contingent consideration from CWLH Assets acquisition								
2) Contingent consideration (Notes 18, 35 and 38)	-	3,940	-	-	Level 1	Based on the nature and the likelihood of occurrence of the trigger event. Fair value is estimated using 2023 Dated Brent oil price forecasts of US$89.41/bbl at the end of the reporting period and taking into account the time value of money and volatility of oil prices.	Expected future oil price volatility is based on an analysis of Dated Brent oil prices movements.	A significant decrease in Dated Brent oil prices in 2023 would result to the reversal of the contingent payments recognised.
Others - contingent consideration from PenMal Assets acquisition								
3) Contingent consideration (Notes 20 and 38)	-	3,000	-	4,429	Level 1	Based on the actual average Dated Brent prices in 2022 of US$101.32/bbl.	-	-

40. SEGMENT INFORMATION

Information reported to the Group's Chief Executive Officer (the chief operating decision maker) for the purposes of resource allocation is focused on two reportable/business segments driven by different types of activities within the upstream oil and gas value chain, namely producing assets and secondly development and exploration assets. The geographic focus of the business is on Southeast Asia ("SEA") and Australia.

Revenue and non-current assets information based on the geographical location of assets respectively are as follows:

	Producing assets		Exploration/ development		
	Australia USD'000	SEA USD'000	SEA USD'000	Corporate USD'000	Total USD'000
2022					
Revenue					
Liquids revenue	328,863	89,620	-	-	418,483
Gas revenue	-	3,119	-	-	3,119
	328,863	**92,739**	**-**	**-**	**421,602**
Production cost	(189,041)	(61,659)	-	-	(250,700)
DD&A	(57,835)	(3,405)	(235)	(359)	(61,834)
Administrative staff costs	(13,839)	(4,073)	(2,020)	(9,286)	(29,218)
Other expenses	(8,872)	(1,877)	(8,188)	(3,368)	(22,305)
Impairment	-	(13,534)	-	-	(13,534)
Other income	24,226	2,718	965	124	28,033
Finance costs	(6,698)	(2,033)	(903)	(1,774)	(11,408)
Other financial gains	1,904	-	-	-	1,904
Profit/(Loss) before tax	**78,708**	**8,876**	**(10,381)**	**(14,663)**	**62,540**
Additions to non-current assets	110,405	582	23,266	69	134,322
Non-current assets	424,017	101,835	115,390	231	641,473

	Producing assets		Exploration/ development		
	Australia USD'000	SEA USD'000	SEA USD'000	Corporate USD'000	Total USD'000
2021 (Restated)*					
Revenue					
Liquids revenue	293,566	45,644	-	-	339,210
Gas revenue	-	984	-	-	984
	293,566	**46,628**	**-**	**-**	**340,194**
Production cost	(182,001)	(29,895)	-	-	(211,896)
DD&A	(75,848)	(3,621)	(281)	(465)	(80,215)
Administrative staff costs	(13,364)	(1,433)	(1,612)	(8,659)	(25,068)
Other expenses	(14,970)	(2,466)	(5,875)	(2,870)	(26,181)
Other income	7,038	9	76	559	7,682
Finance costs	(7,452)	(875)	(503)	(245)	(9,075)
Other financial gains	-	-	266	-	266
Profit/(Loss) before tax	**6,969**	**8,347**	**(7,929)**	**(11,680)**	**(4,293)**
Additions to non-current assets	57,130	64,117	4,744	183	126,174
Non-current assets	367,451	59,892	90,938	719	519,000

Non-current assets as shown here comprises oil and gas properties, intangible exploration assets, right-of-use assets, other receivables and prepayment and plant and equipment used in corporate offices. Deferred tax assets are excluded from the segmental note but included in the Group's consolidated statement of financial position.

Revenue arising from producing assets relates to the Group's single customer with respect to oil sales in Australia, and a different single customer for oil and gas sales in Malaysia. There is an active market for the Group's oil and gas.

*Certain 2021 comparative information has been restated and reclassified between line items. Please refer to Note 45.

41. FINANCIAL CAPITAL COMMITMENTS

Certain PSCs and service concessions have firm capital commitments. The Group has the following outstanding minimum commitments:

SEA portfolio PSC operational commitments

	2022 USD'000	2021 USD'000
Not later than one year	400	400
One to five years	12,000	12,000
More than 5 years	10,300	10,700
	22,700	**23,100**

The SEA portfolio PSC operational commitments as at 31 December 2022 amounted to US$17.3 million (2021: US$ 17.3 million), and relates to the minimum work commitment outstanding for the Block 46/07 PSC and the Lemang PSC. The operational commitments also include training commitment of US$5.4 million (2021: US$5.8 million), for the Block 46/07 PSC, Block 51 PSC and the PenMal Assets.

Work commitment

Under the terms of the Block 46/07 PSC, Jadestone is committed to drill one more appraisal well on the block. The Group plans to drill an appraisal well on the Nam Du field to facilitate transition of 3C resource to 2C status. This well would be retained for future use as a Nam Du gas producer. The current exploration phase expires on 29 June 2024. If necessary, the Group will request an extension to this deadline to align drilling of the appraisal well with development of the Nam Du/U Minh gas fields.

As part of the acquisition under the terms of the Lemang PSC, the Group, as the operator, has inherited unfulfilled work commitments of US$7.3 million consisting of one exploration well and a 3D seismic programme. The work commitments should have been completed during the exploration phase of the PSC by the previous owner. It has been agreed with the Indonesian regulator that the work commitments can be completed after first gas in 2024 but before the end of 2026.

Training commitment

Under the terms of the Block 46/07 PSC and Block 51 PSC, the Group commits to pay an annual training commitment amount of US$0.4 million to Petrovietnam until the expiration of the respective PSC licence. The training commitment amount is for the purpose of developing the local employees in the oil and gas industry.

As part of the acquisition under the terms of the PenMal Assets, the Group has inherited net training commitments of US$0.3 million and US$0.1 million for PM323 PSC and PM318 PSC, respectively. Funds provided with respect to this training commitment are applied to the development of local employees in the oil and gas industry. The training commitments are required to be completed before the expiration of the respective PSC.

Capital commitments

The Group has the following capital commitments for expenditure that were contracted for at the end of the reporting year but not recognised as liabilities for Stag and Montara:

	2022 USD'000	2021 USD'000
Not later than one year	310	5,254

The capital commitment of US$0.3 million as at 2022 year end predominately arose from the installation of produced water treatment unit and subsea control system upgrade at Montara, which are expected to be completed by end of 2023. The 2021 capital commitment of US$5.3 million mainly related to long leads for 50H and 51H drilling programme at Stag, which were completed during 2022.

42. CONTINGENT LIABILITY

On 17 June 2022, a loss of containment of between three and five cubic metres of oil occurred at the Montara Venture FPSO. The facility was shut-in immediately and the incident was reported to the local regulator. The local regulator has commenced an investigation into the incident for potential breach of the local regulations. The investigation is ongoing as at year end and is anticipated to continue throughout 2023. It is too early to reliably estimate the outcome of the investigation and if any prosecution will eventuate.

43. EVENTS AFTER THE END OF THE REPORTING PERIOD

Acquisition of interest in Sinphuhorm gas field

On 19 January 2023, the Group has executed a sale and purchase agreement with Salamander Energy (S.E. Asia) Limited (the "Seller"), an affiliate of PT Medco Energi Internasional Tbk, to acquire the Seller's interest in three legal entities, which collectively own a 9.52% non-operated interest in the producing Sinphuhorm gas field and a 27.2% interest in the Dong Mun gas discovery onshore northeast Thailand. The acquisition was completed on 23 February 2023, for a cash consideration of US$27.9 million post closing adjustments. The effective date of the transaction is 1 January 2022.

New debt facility

On 17 February 2023, the Group announced that it has closed a US$50.0 million debt facility ("Interim Facility") with two international banks. The closing of the Interim Facility forms part of the previously announced plan to arrange a RBL, which is a key element of the Group's medium-term financing strategy to fund development capital at the Indonesian Akatara Gas Project and further growth through merger and acquisition.

The Interim Facility has a term of nine months and carries an initial margin of 450 basis points over secured overnight financing rate, which steps up in the event repayment occurs more than three months after closing. The RBL workstreams are progressing in line with management expectations and signing of the RBL facility agreement is targeted for May 2023, superseding the Interim Facility.

Montara operations update

The production at Montara was restarted on 21 March 2023. In a carefully planned restart programme, production recommenced from the H6 well on the Montara field, with further wells to follow, including the first Skua subsea well which will be brought on line progressively. Production rates will increase with the systematic opening of additional wells in line with the restart plan.

44. RELATED PARTY TRANSACTIONS

Internal reorganisation

During the comparative period, on 23 April 2021, pursuant to the internal reorganisation, a transfer of beneficial interest agreement was entered into between Jadestone Energy Inc. ("JEI"), Jadestone Energy Holdings Limited ("JEHL") and Daniel Young, the former Chief Financial Officer. Under the transfer of beneficial interest agreement, JEI transferred the beneficial interest in 100,000 of the Company's shares to Daniel Young, with a corresponding reduction in the issuance of any new JEP shares due to Daniel Young in exchange for his existing JEI shares transferred to JEHL.

The purpose of this transfer was to ensure that the adjusted total outstanding number of Jadestone Energy plc shares of 463,649,477 at the completion of the internal reorganisation was exactly equal to the number of outstanding Jadestone Energy Inc. shares of 463,649,477 immediately prior to the completion of the reorganisation.

Compensation of key management personnel

	2022 USD'000	2021 USD'000
Short-term benefits	7,717	8,179
Other benefits	2,027	1,295
Share-based payments	810	713
	10,554	**10,187**

The total remuneration of key management members in 2022 (including salaries and benefits) was US$10.5 million (2021: US$10.2 million) and recognised as part of the Group's administrative staff costs as disclosed in Note 7.

Compensation of Directors

	Short-term benefits[(a)] USD'000	Other benefits[(a)] USD'000	Share-based payments USD'000	Total compensation USD'000
2022				
A. Paul Blakeley	1,236	-	271	1,507
Bert-Jaap Dijkstra	268	23	35	326
Dennis McShane	155	-	6	161
Iain McLaren	105	-	4	109
Robert Lambert	95	-	4	99
Cedric Fontenit	90	-	4	94
Lisa Stewart	100	-	13	113
David Neuhauser	80	-	4	84
Jenifer Thien	71	-	-	71
Daniel Young	428	353	-	781
	2,628	**376**	**341**	**3,345**

	Short-term benefits[(a)] USD'000	Other benefits[(a)] USD'000	Share-based payments USD'000	Total compensation USD'000
2021				
A. Paul Blakeley	1,367	148	302	1,817
Daniel Young	748	210	(75)	883
Dennis McShane	155	-	10	165
Iain McLaren	105	-	7	112
Robert Lambert	95	-	7	102
Cedric Fontenit	95	-	7	102
Lisa Stewart	90	-	13	103
David Neuhauser	80	-	7	87
	2,735	**358**	**278**	**3,371**

[(a)] Short-term benefits comprise salary, director fee as applicable, performance pay, pension and other allowances. Other benefits comprise benefits-in-kind.

45. RESTATEMENT AND RECLASSIFICATION OF COMPARATIVE FIGURES

Certain comparative figures in the consolidated financial statements of the Group have been restated arising from a change in accounting policy as well as reclassifications to conform to the presentation in the current period and to better reflect the nature of the respective items in the Group's consolidated financial statements.

The prior year restatement made was in relation to the change in accounting policy on the measurement of under/overlift, from recorded at the prevailing market price to recorded at the lower of cost and net realisable value as disclosed in Note 2.

The reclassifications made in the consolidated statement of financial position are related to the restricted cash held by the Group in relation to deposits placed for bank guarantees with respect to the PenMal Assets and Australian office buildings as a result of the April 2022 IFRIC Agenda item "Demand Deposits with Restrictions on Use arising from a Contract with a Third Party (IAS 7 *Statement of Cash Flows*). Additionally, the Group reclassed the fair value proceeds received from the issuance of shares to share premium account, plus incentive scheme payable the Group's employees are now recognised as an accrual. The reclassifications do not have impact on the consolidated statement or profit or loss and other comprehensive income and consolidated statement of cash flows.

The reclassifications made in the consolidated statement of cash flows are related to the interest paid, which now classified in accordance to its nature of activities. The reclassifications do not have impact on the consolidated statement or profit or loss and other comprehensive income and consolidated statement of financial position.

The restatements and reclassifications impact the following items:

	As previously reported USD'000	Restatements and reclassifications USD'000	As restated and reclassified USD'000
Consolidated statement of profit or loss and other comprehensive income for the year ended 31 December 2021			
Production costs	(206,523)	(5,373)	(211,896)
Income tax expense	(14,822)	2,042	(12,780)
Consolidated statement of financial position as at 31 December 2021			
Deferred tax assets	25,278	1,111	26,389
Trade and other receivables	37,951	(5,373)	32,578
Cash and cash equivalents – non-current	-	852	852
Cash and cash equivalents - current	117,865	(852)	117,013
Share capital	559	(201)	358
Share premium	-	201	201
Accumulated losses	31,692	3,331	(35,023)
Deferred tax liabilities	(67,097)	931	(66,166)
Provisions - current	(1,947)	1,017	(930)
Trade and other payables	(69,090)	(1,017)	(70,107)
Consolidated statement of cash flows for the year ended 31 December 2021			
Profit/(Loss) before tax	1,080	(5,373)	(4,293)
Increase in trade and other receivables	(11,975)	5,373	(6,602)
Interest paid – operating activities	(1,505)	1,505	-
Interest paid – financing activities	-	(74)	(74)
Interest on lease liabilities paid – financing activities	-	(1,222)	(1,222)
Interest on borrowings paid – financing activities	-	(209)	(209)

Company Statement of Financial Position as at 31 December 2022

	Notes	2022 USD'000	2021 Reclassified* USD'000
Assets			
Non-current asset			
Investment in subsidiaries	5	26,838	25,905
Loan to a subsidiary	7	265,370	365,598
Total non-current asset		**292,208**	**391,503**
Current assets			
Amount owing by subsidiaries	7	32,521	4,812
Prepayments		20	-
Cash and cash equivalents		18,814	2,912
Total current assets		**51,355**	**7,724**
Total assets		**343,563**	**399,227**
Equity and liabilities			
Equity			
Capital and reserves			
Share capital	8	339	358
Share premium	8	983	201
Merger reserve		61,068	61,068
Share-based payment reserve	10	26,907	25,936
Capital redemption reserve		21	-
Retained earnings		245,869	306,408
Total equity		**335,187**	**393,971**

	Notes	2022 USD'000	2021 USD'000
Liabilities			
Current liabilities			
Other payables and accruals	11	851	212
Amount owing to a subsidiary	7	7,525	5,044
Total current liabilities		**8,376**	**5,256**
Total liabilities		**8,376**	**5,256**
Total equity and liabilities		**343,563**	**399,227**

During the year, the Company made a loss after tax of US$35.3 million (2021: US$7.0 million loss).

*Certain 2021 comparative information has been reclassified between line items. Please refer to Note 13.

Company Statement of Changes in Equity for the year ended 31 December 2022

	Share capital USD'000	Share premium USD'000	Capital redemption reserve USD'000	Share-based payments reserve USD'000	Merger reserve USD'000	Retained earnings USD'000	Total USD'000
As at incorporation date, 22 January 2021	68	-	-	-	-	-	68
Transfer of share-based payment reserve to the Company following internal reorganisation	-	-	-	25,493	-	-	25,493
Share-based compensation:							
Company	-	-	-	31	-	-	31
Subsidiaries	-	-	-	412	-	-	412
Dividend paid (Note 9)	-	-	-	-	-	(7,745)	(7,745)
Shares issued	321,407	201	-	-	61,068	-	382,676
Capital reduction	(321,117)	-	-	-	-	321,117	-
Total transactions with owners	**290**	**201**	**-**	**25,936**	**61,068**	**313,372**	**400,867**
Loss and total comprehensive income for the period	-	-	-	-	-	(6,964)	(6,964)
As at 31 December 2021 (Reclassified)*	**358**	**201**	**-**	**25,936**	**61,068**	**306,408**	**393,971**

	Share capital USD'000	Share premium USD'000	Capital redemption reserve USD'000	Share-based payments reserve USD'000	Merger reserve USD'000	Retained earnings USD'000	Total USD'000
As at 1 January 2022 (Reclassified)*	358	201	-	25,936	61,068	306,408	393,971
Share-based compensation:							
Company	-	-	-	38	-	-	38
Subsidiaries	-	-	-	933	-	-	933
Dividend paid (Note 9)	-	-	-	-	-	(9,216)	(9,216)
Shares issued	2	782	-	-	-	-	784
Shares repurchases	(21)	-	21	-	-	(16,070)	(16,070)
Total transactions with owners	**(19)**	**782**	**21**	**971**	**-**	**(25,286)**	**(23,531)**
Loss and total comprehensive income for the year	-	-	-	-	-	(35,253)	(35,253)
As at 31 December 2022	**339**	**983**	**21**	**26,907**	**61,068**	**245,869**	**355,187**

*Certain 2021 comparative information has been reclassified between line items. Please refer to Note 13.

Company Notes to the Financial Statements for the year ended 31 December 2022

1. CORPORATE INFORMATION

The Company was incorporated on 22 January 2021 in the United Kingdom and registered in England and Wales. The Company's head office is located at 3 Anson Road, #13-01 Springleaf Tower, Singapore 079909. The registered office of the Company is Suite 1, 7th Floor, 50 Broadway, London, United Kingdom SW1H OBL.

The Company's ordinary shares are listed on AIM, a market regulated by the London Stock Exchange plc.

The principal activity of the Company is that of investment holding in the production and exploration of oil and gas.

2. BASIS OF PREPARATION

The Company meets the definition of a qualifying entity under FRS 100, and as such these financial statements have been prepared in accordance with Financial Reporting Standard 101 *Reduced Disclosure Framework* (FRS 101). The financial statements have been prepared under the historical cost convention.

As permitted by s408 of the Companies Act 2006 the Company has elected not to present its own statement of profit or loss and other comprehensive income for the period. The loss attributable to the Company is disclosed in the footnote to the Company's statement of financial position. The auditor's remuneration for the audit is disclosed in Note 11 to the consolidated financial statements. The Company has also applied the following disclosure exemptions under FRS 101:

- paragraphs 45(b) and 46 to 52 of IFRS 2 *Share-based Payment* (details of the number and weighted average exercise prices of share options, and how the fair value of goods or services received was determined), as equivalent disclosures are included within the consolidated financial statements;

- all requirements of IFRS 7 *Financial Instruments: Disclosures*, as equivalent disclosures are included in the consolidated financial statements;

- paragraphs 91 to 99 of IFRS 13 *Fair Value Measurement* (disclosure of valuation techniques and inputs used for fair value measurement of assets and liabilities);

- paragraph 38 of IAS 1 *Presentation of Financial Statements* - the requirement to disclose comparative information in respect of:
  - paragraph 79(a)(iv) of IAS 1 (a reconciliation of the number of shares outstanding at the beginning and end of the period); and
  - paragraph 73(e) of IAS 16 *Property, Plant and Equipment* (reconciliations between the carrying amount at the beginning and end of the period).

- IAS 7 *Statement of Cash Flows*;

- paragraphs 30 and 31 of IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors* (the requirement for the disclosure of information when an entity has not applied a new IFRS that has been issued but is not yet effective); and

- paragraph 17 of IAS 24 *Related Party Disclosures* (key management compensation), and the other requirements of that standard to disclose related party transactions entered into between two or more members of a group, provided that any subsidiary which is a party to the transaction is wholly owned by such a member.

3. ACCOUNTING POLICIES

The Company's accounting policies are aligned with the Group's accounting policies as set out within the consolidated financial statements, with the addition of the following:

Investment in subsidiaries

Investments in subsidiaries are held at cost less any accumulated provision for impairment losses. Investment in subsidiaries also consist of capital contribution by the Company to its subsidiaries by assuming the ownership of the LTIP awards previously granted by the former parent company of the Group.

4. CRITICAL ACCOUNTING JUDGEMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

In the process of applying the Company's accounting policies, management is required to make judgements, estimates and assumptions about the carrying amounts of assets and liabilities that are not readily apparent from other sources. The estimates and associated assumptions are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognised in the period in which the estimate is revised, if the revision affects only that period, or in the period of the revision and future periods, if the revision affects both current and future periods.

The following is the critical judgement and estimate that the management has made in the process of applying the Company's accounting policies that have the most significant effect on the amounts recognised in the financial statements.

- **Recoverability of the loan to a subsidiary, Jadestone Energy Holdings Ltd**

  The recoverability of the loan is based on the evaluation of expected credit loss. A considerable amount of estimation uncertainty exists in assessing the ultimate realisation of the loan, including the past collection history from Jadestone Energy Holdings Ltd ("JEHL") plus estimation of the future profitability of JEHL, with its sole source of income being dividend income to be received from JEHL's subsidiaries. Accordingly, the management exercised judgement in estimating the future profitability of the oil and gas operations held by the JEHL's subsidiaries.

  In estimating the future profitability of the JEHL's subsidiaries, management estimated the available reserves owned by the subsidiaries and performed sensitivity analysis on the estimated reserves as disclosed in Note 3 of the consolidated financial statements. Management concluded that the subsidiaries will be able to declare sufficient dividend income to JEHL based on the estimated reserves and also after taking into the account the sensitivity analysis.

  Management also considered the future hydrocarbon prices in determining the future profitability of the JEHL's subsidiaries. The future hydrocarbon price assumptions used are highly judgemental and may be subject to increased uncertainty given climate change and the global energy transition. Management further takes into consideration the impact of climate change on estimated future commodity prices with the application of the Paris aligned price assumptions as disclosed in Note 3 of the consolidated financial statements. Based on the analysis performed, the potential future reduction on the hydrocarbon prices as impacted by the climate change and the global energy transition will not significantly impact the future operating cash flows of the subsidiaries. Accordingly, management estimates that the subsidiaries will be able to declare sufficient dividend income to JEHL.

5. INVESTMENT IN SUBSIDIARIES

	2022 USD'000	2021 USD'000
Unquoted share, at cost	-*	-*
Share-based payment:		
At beginning of year/As at incorporation date	25,905	-
Transfer of share-based payment reserve to the Company following internal reorganisation	-	25,493
Share-based compensation at subsidiaries during the year/period	933	412
At end of year/period	**26,838**	**25,905**
	26,838	**25,905**

* Rounded to nearest thousand.

Details of the direct and indirect investments the Company holds are as follows:

Name of the company	Place of incorporation	% voting rights and ordinary shares held 2022	% voting rights and ordinary shares held 2021	Nature of business
Direct				
Jadestone Energy Holdings Ltd (1)	England and Wales	100	100	Investment holdings
Indirect				
Jadestone Energy (Australia) Pty Ltd (2)	Australia	100	100	Production of oil & gas
Jadestone Energy (Australia Holdings) Pty Ltd (2)	Australia	100	100	Investment holdings
Jadestone Energy (CWLH) Pty Ltd (2)	Australia	100	100	Production of oil & gas
Jadestone Energy (Eagle) Pty Ltd (2)	Australia	100	100	Production of oil & gas
Jadestone Energy Inc. (3)	Canada	100	100	Investment holdings
Jadestone Energy International Holdings Inc. (3)	Canada	100	100	Investment holdings
Jadestone Energy (Lemang) Pte Ltd (4)	Singapore	100	100	Exploration
Jadestone Energy Ltd (5)	Bermuda	100	100	Investment holdings
Jadestone Energy (New Zealand) Ltd (6)	New Zealand	100	100	Production of oil & gas

Name of the company	Place of incorporation	% voting rights and ordinary shares held 2022	% voting rights and ordinary shares held 2021	Nature of business
Jadestone Energy (New Zealand Holdings) Ltd [6]	New Zealand	100	100	Investment holdings
Jadestone Energy (Ogan Komering) Ltd [7] *	Canada	100	100	Production of oil & gas
Mitra Energy (Philippines SC- 56) Ltd [5]	Bermuda	100	100	Exploration
Mitra Energy (Philippines SC- 57) Ltd [8]	BVI	100	100	Exploration
Jadestone Energy (PM) Inc. [9]	Bahamas	100	100	Production of oil & gas
Jadestone Energy (Singapore) Pte Ltd [4]	Singapore	100	100	Investment holdings
Jadestone Energy Sdn Bhd [10]	Malaysia	100	100	Administration
Jadestone Energy UK Services Ltd [1]	England and Wales	100	100	Administration
Jadestone Energy (Vietnam) Pte Ltd [4]	Singapore	100	100	Exploration
Mitra Energy (Indonesia Bone) Ltd [8]**	BVI	-	100	Exploration
Mitra Energy (Vietnam 05-1) Pte Ltd [4] ***	Singapore	100	100	Exploration
Mitra Energy (Vietnam Nam Du) Pte Ltd [4]	Singapore	100	100	Exploration
Mitra Energy (Vietnam Tho Chu) Pte Ltd [4]	Singapore	100	100	Exploration

Registered office addresses:
(1) Suite 1, 7th Floor, 50 Broadway, London, United Kingdom SW1H OBL
(2) Atrium Building Level 2, 168-170 St Georges Terrace, Perth WA 6000, Australia
(3) 10th Floor, 595 Howe St., Vancouver BC, V6C 2T5, Canada
(4) 3 Anson Road #13-01, Springleaf Tower, Singapore 079909
(5) 3rd Floor - Par la Ville Place, 14 Par la Ville Road, Hamilton HM08, Bermuda
(6) Bell Gully, 171 Featherston Street, Wellington Central, Wellington, 6011, New Zealand
(7) 29 Tuscany Hills Bay NW, Calgary, Alberta, T3L2G5, Canada
(8) TMF (BVI) Ltd, Palm Grove House, P.O. Box 438, Road Town, Tortola, British Virgin Islands
(9) H&J Corporate Services Ltd, Ocean Centre, Montagu Foreshore, East bay Street, P.O. Box N-3247, Nassau, Bahamas
(10) Level 15-2, Bangunan Imperial Court, Jalan Sultan Ismail, 50250, Kuala Lumpur, Malaysia

* Jadestone Energy (Ogan Komering) Ltd has been dissolved on 10 Mar 2023.

** Mitra Energy (Inodnesia Bone) Ltd has been dissolved on 13 Apr 2022.

*** Mitra Energy (Vietnam 05-1) Pte Ltd has been dissolved on 9 Mar 2023.

6. STAFF NUMBER AND COSTS

The Company has one (2021: one) employee during the year.

The aggregate remuneration comprised:

	2022 USD'000	2021 USD'000
Wages and salaries	141	104
Social security costs	38	4
Defined contribution pension costs	-	-
	179	**108**

7. RELATED PARTY TRANSACTIONS

The Company does not enter into new loan with its subsidiary during the year. In 2021, the Company entered into a loan with its subsidiary, Jadestone Energy Holdings Limited, for the purpose of recovering the amount of the consideration shares issued by the Company to former Jadestone Energy Inc. shareholders as part of the internal reorganisation exercise which was completed on 23 April 2021. The loan is non-interest bearing and repayable on demand or at any time, as agreed with the Company, before 21 April 2031.

Amount owing by subsidiaries are mainly related to payments on behalf, and a receipt on behalf of the Company by a subsidiary for the proceeds from issuance of shares during the period. The amount owing by subsidiaries are non-trade in nature, unsecured, non-interest bearing and repayable on demand.

Amount owing to a subsidiary is mainly related to advances received for the purpose of depositing the funds into the Company's bank account. The amount owing to subsidiaries are non-trade in nature, unsecured, non-interest bearing and repayable on demand.

During the year, the Company entered into the following transactions with:

	2022 USD'000	2021 USD'000
Loan to a subsidiary		
At beginning of the year/As at incorporation date	365,598	-
Loan provided during the year/period	-	382,555
Repayment during the year/period	(68,284)	(12,967)
Unrealised foreign exchange differences	(31,943)	(3,990)
At end of the year/period	**265,371**	**365,598**
Subsidiaries		
Advances	31,971	23,856
Repayment received	(4.200)	(19,033)
Payment on behalf by	(61)	(12)

8. SHARE CAPITAL AND SHARE PREMIUM ACCOUNT

	No. of shares	Share capital USD'000	Share premium account USD'000
Issued and fully paid			
As at incorporation date, 22 January 2021, at £1 each	50,000	68	-
Sub-division of shares, at £0.50 each	50,000	-	-
Ordinary shares issued during the period, at £0.50 each	464,981,238	321,407	201
Capital reduction, at £0.499 each	-	(321,117)	-
As at 31 December 2021	**465,081,238**	**358**	**201**
Issued during the year	1,446,108	2	782
Share repurchases	(18,173,683)	(21)	-
As at 31 December 2022	**448,363,663**	**339**	**983**

On 6 April 2021, the Company sub-divided its ordinary shares into 100,000 units of share, at £0.50 each.

On 4 May 2021, the High Court of Justice, Business and Property Court, Companies Court in England and Wales approved the reduction of share capital of the Company pursuant to section 648 of the Act by cancelling the paid-up capital of the Company to the extent of 49.9 pence on each ordinary share of £0.50 in the issued share capital of the Company. The effective date of the capital reduction was 6 May 2021.

On 2 August 2022, the Company announced the launch of a share buyback programme (the "Programme") in accordance with the authority granted by the shareholders at the Company's annual general meeting on 30 June 2022. The maximum amount of the Programme was US$25.0 million, and the Programme will not exceed 46,574,528 ordinary shares.

As at 31 December 2022, the Company had acquired 18.2 million shares at a weighted average cost of £0.76 per share, resulting in an accumulated total of US$16.1 million.

During the year, employee share options of 1,446,108 were exercised and issued at an average price of GB£ 0.42 per share (2021: 3,238,427; GB£0.33 per share).

The Company has one class of ordinary share. Fully paid ordinary shares with par value of £0.001 per share carry one vote per share without restriction, and carry a right to dividends as and when declared by the Company.

9. DIVIDENDS

The Company has sufficient distributable reserves to declare dividends. The distributable reserves were created through the reduction of share capital of the Company in May 2021 (Note 8 of Company level financial statements). The dividends declared were in compliance with the Act.

On 20 September 2022, the Directors declared a 2022 interim dividend of 0.65 US cents/share, equivalent to a total distribution of US$3.0 million. The dividend was paid on 11 October 2022.

On 6 June 2022, the Directors recommended a final 2021 dividend of 1.34 US cents/share, equivalent to a total distribution of US$6.2 million, or US$9.0 million in respect of total 2021 dividends. The dividend was approved by shareholders on 30 June 2022 and paid on 5 July 2022.

On 9 September 2021, the Directors declared a 2021 interim dividend of 0.59 US cents/share, equivalent to a total distribution of US$2.8 million. The dividend was paid on 1 October 2021.

On 11 June 2021, the Directors declared the second interim 2020 dividend of 1.08 US cents/share, equivalent to a total distribution of US$5.0 million, or US$7.5 million in respect of total 2020 dividends. The dividend was paid on 30 June 2021.

10. SHARE-BASED PAYMENTS RESERVE

The total expense arising from share-based payments of US$0.1 million (2021: US$0.1 million) was recognised in profit or loss for the year ended 31 December 2022.

On 15 May 2019, the Company adopted, as approved by the shareholders, the amended and restated stock option plan, the performance share plan, and the restricted share plan (together, the "LTI Plans"), which establishes a rolling number of shares issuable under the LTI Plans up to a maximum of 10% of the Company's issued and outstanding ordinary shares at any given time. Options under the stock option plan will be exercisable over periods of up to 10 years as determined by the Board.

10.1 Share options

Management has applied the Black-Scholes option-pricing model, with the following assumptions, was used to estimate the fair value of the options at the date of grant:

	Options granted on	
	9 March 2022	**18 March 2021**
Risk-free rate	1.34% to 1.38%	0.49% to 0.61%
Expected life	5.5 to 6.5 years	5.5 to 6.5 years
Expected volatility[1]	63.0% to 66.7%	65.2% to 67.6%
Share price	GB£ 1.01	GB£ 0.65
Exercise price	GB£ 0.92	GB£ 0.77
Expected dividends	1.96%	1.79%

10.2 Performance shares

The performance measures for performance shares incorporate both a relative and absolute total shareholder return ("TSR") calculation on a 70:30 basis to compare performance vs. peers (relative TSR) and to ensure alignment with shareholders (absolute TSR).

Relative TSR: measured against the TSR of peer companies; the size of the pay out is based on Jadestone's ranking against the TSR outcomes of peer companies.

Absolute TSR: share price target plus dividend to be set at the start of the performance period and assessed annually; the threshold share price plus dividend has to be equal to or greater than a 10% increase in absolute terms to earn any pay out at all, and must be 25% or greater for target pay out.

[1] Expected volatility was determined by calculating the average historical volatility of the daily share price returns over a period commensurate with the expected life of the awards for a group of ten peer companies.

A Monte Carlo simulation model was used by an external specialist, with the following assumptions to estimate the fair value of the performance shares at the date of grant:

	Performance shares granted on	
	9 March 2022	**18 March 2021**
Risk-free rate	1.39%	0.06%
Expected volatility[1]	53.1%	51.4%
Share price	GB£ 1.01	GB£ 0.77
Exercise price	N/A	N/A
Expected dividends	1.71%	2.64%
Post-vesting withdrawal date	N/A	N/A
Early exercise assumption	N/A	N/A

10.3 Restricted shares

Restricted shares are granted to certain senior management personnel as an alternative to cash under exceptional circumstances and to provide greater alignment with shareholder objectives. These are shares that vest three years after grant, assuming the employee has not left the Group. They are not eligible for dividends prior to vesting.

The following assumptions were used to estimate the fair value of the restricted shares at the date of grant, discounting back from the date they will vest and excluding the value of dividends during the intervening period:

	Restricted shares granted on		
	22 August 2022	**9 March 2022**	**18 March 2021**
Risk-free rate	1.73%	1.39%	0.08%
Share price	GB£ 0.90	GB£ 1.01	GB£ 0.77
Expected dividends	1.73%	1.71%	2.64%

[1] Expected volatility was determined by calculating Jadestone's average historical volatility of each trading day's log growth of TSR over a period between the grant date and the end of the performance period.

The following table summarises the options/shares under the LTI plans outstanding and exercisable as at 31 December 2022:

			Shares Options			
	Performance shares	Restricted shares	Number of options	Weighted average exercise price GB£	Weighted average remaining contract life	Number of options exercisable
As at 1 January 2021	**683,200**	**101,063**	**25,192,842**	**0.40**	**7.78**	**12,212,827**
New options/share awards issued	1,136,512	50,570	2,852,631	0.77	9.21	-
Vested during the year	-	-	-	0.42	6.92	3,776,672
Accelerated vesting during the year	-	-	198,687	0.55	8.39	198,687
Exercised during the year	-	-	(3,238,427)	0.33	-	(3,238,427)
Cancelled during the year	(332,819)	-	(3,690,244)	0.46	-	(1,539,905)
As at 31 December 2021	**1,486,893**	**151,633**	**21,315,489**	**0.45**	**7.16**	**11,409,854**
New options/share awards issued	1,385,013	293,655	1,023,561	0.92	9.19	-
Vested during the year	-	-	-	0.50	6.27	2,010,007
Accelerated vesting during the year	-	-	1,354,702	0.46	6.45	1,354,702
Exercised during the year	-	-	(1,446,108)	0.42	-	(1,446,108)
Cancelled during the year	(147,906)	-	(120,854)	0.50	-	(891,270)
As at 31 December 2022	**2,724,000**	**445,288**	**22,176,790**	**0.48**	**6.33**	**12,437,185**

	Number of options	Range of exercise price GB£	Weighted average exercise price GB£	Weighted average remaining contract life
Share options exercisable as at 31 December 2021	11,409,854	0.26 - 0.99	0.38	6.18
Share options exercisable as at 31 December 2022	12,437,185	0.26 - 0.99	0.41	5.46

11. OTHER PAYABLES

	2022 USD'000	2021 USD'000
Other payables	456	1
Accruals	395	211
	851	**212**

Other payables and accruals principally comprise amounts outstanding for non-trade related business expenditures. The average credit period is less than 30 days. For most suppliers, no interest is charged on the payables in the first 30 days from the date of invoice. Thereafter, interest may be charged on outstanding balances at varying rates of interest. The Company has financial risk management policies in place to ensure that all payables are settled within the pre-agreed credit terms.

12. EVENTS AFTER THE END OF THE REPORTING PERIOD

Acquisition of interest in Sinphuhorm gas field

On 19 January 2023, the Group has executed a sale and purchase agreement with Salamander Energy (S.E. Asia) Limited (the "Seller"), an affiliate of PT Medco Energi Internasional Tbk, to acquire the Seller's interest in three legal entities, which collectively own a 9.52% non-operated interest in the producing Sinphuhorm gas field and a 27.2% interest in the Dong Mun gas discovery onshore northeast Thailand. The acquisition was completed on 23 February 2023, for a headline cash consideration of US$27.8 million post customary closing adjustments. The effective date of the transaction is 1 January 2022.

New debt facility

On 17 February 2023, the Group announced that it has closed a US$50.0 million debt facility ("Interim Facility") with two international banks. The closing of the Interim Facility forms part of the previously announced plan to arrange a reserves-based lending facility ("RBL"), which is a key element of the Group's medium-term financing strategy to fund development capital at the Indonesian Akatara Gas Project and further growth through merger and acquisition.

The Interim Facility has a term of nine months and carries an initial margin of 450 basis points over secured overnight financing rate, which steps up in the event repayment occurs more than three months after closing. The RBL workstreams are progressing in line with management expectations and signing of the RBL facility agreement is targeted for May 2023, superseding the Interim Facility.

Montara operations update

The production at Montara was restarted on 21 March 2023. In a carefully planned restart programme, production recommenced from the H6 well on the Montara field, with further wells to follow, including the first Skua subsea well which will be brought on line progressively. Production rates will increase with the systematic opening of additional wells in line with the restart plan.

13. RECLASSIFICATION OF COMPARATIVE FIGURES

Certain comparative figures in the financial statements of the Company have been reclassified to conform to the presentation in the current period and to better reflect the nature of the respective items in the Company's financial statements.

The reclassification made in the statement of financial position is related to the fair value proceeds received from the issuance of shares, which is recorded in the share premium account.

The reclassification impacts the following items:

	As previously reported USD'000	Reclassification USD'000	As reclassified USD'000
Statement of financial position as at 31 December 2021			
Share capital	559	(201)	358
Share premium	-	201	201

GLOSSARY

2P	the sum of proved and probable reserves, reflecting those reserves with 50% probability of quantities actually recovered being equal or greater to the sum of estimated proved plus probable reserves
2C	best estimate contingent resource, being quantities of hydrocarbons which are estimated, on a given date, to be potentially recoverable from known accumulations but which are not currently considered to be commercially recoverable
AAKBNLP	Abu, Abu Kecil, Bubu, North Lukut, and Penara oilfields
AIM	Alternative Investment Market
API	American Petroleum Institute gravity
bbl	barrel
bbls/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
DD&A	depletion, depreciation and amortisation
EBITDAX	earnings before interest tax, depreciation, amortisation and exploration
FPSO	floating production storage and offloading
FSO	floating storage and offloading
GB pence, GBp	Great Britain pence
GHG	greenhouse gases
IFRS	International Financial Reporting Standards
LPG	Liquefied petroleum gas
mcf	thousand cubic feet of natural gas
mm	million
mmbbls	million barrels
mmboe	million barrels of oil equivalent
NOPTA	National Offshore Petroleum Titles Administrator
opex	operating expenditures
OPGGS	Offshore Petroleum & Greenhouse Gas Storage Act (2006)
PETRONAS	Petroliam Nasional Berhad
PITA	Petroleum Income Tax
PRRT	Petroleum Resource Rent Tax
PSC	production sharing contract
RBL	reserves based loan
reserves	hydrocarbon resource that is anticipated to be commercially recovered from known accumulations from a given date forward
SOFR	Secured Overnight Financing Rate
TCFD	Task Force on Climate-Related Financial Disclosures
US$ or USD	United States dollar

The technical information contained in this announcement has been prepared in accordance with the June 2018 guidelines endorsed by the Society of Petroleum Engineers, World Petroleum Congress, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers Petroleum Resource Management System.

A. Shahbaz Sikandar of Jadestone Energy plc, Group Subsurface Manager with a Masters degree in Petroleum Engineering, and who is a member of the Society of Petroleum Engineers and has worked in the energy industry for more than 25 years, has read and approved the technical disclosure in this regulatory announcement.

The information contained within this announcement is considered to be inside information prior to its release, as defined in Article 7 of the Market Abuse Regulation No. 596/2014 which is part of UK law by virtue of the European Union (Withdrawal) Act 2018, and is disclosed in accordance with the Company's obligations under Article 17 of those Regulations.