RNS Number : 1559T
IOG PLC
16 March 2023

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IOG plc

Final Audited Results for the Year Ended 31 December 2022

IOG plc ("IOG", or "the Company"), (AIM: IOG.L), is pleased to announce its final audited results for the Year Ended 31 December 2022.

2022 Highlights

Corporate and Operational

- First Gas delivered from Blythe on 13 March and Elgood on 15 March 2022
- Gross average gas sales of 27.4 mmscfe/d and condensate sales of 1067 MT from First Gas to year end, at average Production Efficiency of 58.6%
- Southwark A1 well drilling suspended due to fluid losses above reservoir section
- Southwark A2 well drilled, completed and stimulated, but suspended post-year end after achieving 2.5 mmscf/d gas flow rate on well test after remediation of water producing stimulated zones
- 2022 Scope 1 and 2 emissions intensity estimated at 0.8 kgCO_2e/boe (North Sea average: 21.2 kgCO_2e/boe[1])
- Total Reportable Incident Rate (TRIR[2]) of 3.6 per 200,000 manhours for 2022

Financial

- Total revenue before sales deductions of £79.6 million (2021: £nil), of which £76.0 million related to gas and £3.6 million condensate
- Weighted average realised 2022 gas price of 201.4 p/therm and $805/MT for condensate
- Gross profit of £51.8 million, cost of sales of £23.6 million and EBITDAX[3] of £63.1 million for the period
- Net loss of £28.4 million (2021: £2.4 million), including a £43.4 million impairment of Southwark and £7.6 million impairment of Nailsworth and Elland
- Loss per share of 5.4p (2021: 0.4p loss); adjusted earnings per share of 4.3p after exceptional one-off items
- Cash balance at period end of £32.4 million (2021: £34.7 million), including restricted cash of £5.7 million (2021: £3.4 million)
- Group net debt at year end £68.2 million (2021: £56.6 million)
- Accrued opex of £10.1 million, equating to gross unit opex of 24.0 p/therm (2021: N/A)
- £8.6 million (2021: £8.3 million) interest paid on €100 million September 2024 senior secured bond ("Bond")
- 2.7 mmscf/d fixed month-ahead in certain months in 2H 2022 at prices from 263 p/therm to 444 p/therm

Board and Management

- Rupert Newall appointed as Chief Executive Officer (CEO), Dougie Scott as Chief Operating Officer (COO) and Executive Director, and John Arthur as Chief Financial Officer (CFO, non-board) in October 2022

Post Year End Developments

- Southwark A2 well suspended and further in-depth review of deliverability initiated
- Blythe H2 well spudded in March 2023, intended to increase gas production, limit water production and maximise reserve recovery from the Blythe reservoir
- Nine Southern North Sea blocks applied for across five licences areas in the 33rd UK Offshore Licensing Round, as operator of the 50:50 joint venture with CER
- Fiona MacAulay to stand down as Chair of the Company at the 2023 AGM, with Esa Ikaheimonen named as Interim Chair and a process underway to recruit two further Non-Executive Directors
- Cash balance of £32.6 million as at 15 March, including restricted cash of £6.2 million
- Over January and February 2023, gross average production from the Blythe H1 well was 15.9 mmscf/d, with Production Efficiency of 89.7%

[1] Emissions intensity is measured in kilograms of carbon dioxide equivalent per barrel of oil equivalent of production, kgCO_2e/boe, on a Scope

1 and 2 basis. North Sea average is taken from the NSTA Emissions Monitoring Report, September 2022.

[2] Total Reportable Incident Rate (TRIR) includes all incidents reportable by law to UK regulators, irrespective of size or consequence, whether involving IOG personnel, duty holders or contractors, per 200,000 hours worked

[3] EBITDAX is defined as profit or loss before net finance expense, income tax expense, depreciation of property, plant and equipment and right-of-use assets, amortisation of intangible assets, impairment of property, plant and equipment, and foreign exchange gain or loss.

Adjusted earnings per share is defined as earnings per share before exceptional one-off items, i.e. in respect of 2022, the Southwark, Nailsworth and Elland impairments

Net debt is defined as total loans, primarily the EUR denominated Bond, less restricted cash and cash equivalents.

Rupert Newall, CEO of IOG, commented:

"Having become the UK's newest gas producer in March 2022, IOG then experienced a number of production issues followed by the very disappointing Southwark A2 well result shortly after year end. Our FY 2022 results reflect this operational performance amid a very volatile gas market. Pending the outcome of the detailed evaluation of options for a commercial forward plan for Southwark, we have taken a significant impairment. While this non-cash impairment drove a full-year loss, adjusted earnings of 4.3p/share reflect underlying profitability.

As a very well aligned new leadership team, we are already rolling out our operational and financial improvement strategy, seeking to deliver production resilience, reduce costs and maximise cash flow. Operating efficiency at Blythe is much improved this quarter and we spudded the Blythe H2 well on 5th March, targeting 30-40 mmscf/d initial gross production rates by mid-year. We also continue with rigorous review of our portfolio to ensure we allocate capital in a prudent and disciplined way."

This announcement contains inside information for the purposes of Article 7 of the Market Abuse Regulation (EU) 596/2014 as it forms part of UK domestic law by virtue of the European Union (Withdrawal) Act 2018 ("MAR"), and is disclosed in accordance with the company's obligations under Article 17 of MAR.

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About IOG:

IOG is a UK developer and producer of indigenous offshore gas. The Company began producing gas in March 2022 via its offshore and onshore Saturn Banks production infrastructure. In addition to its production assets, IOG operates several UK Southern North Sea licences containing gas discoveries and prospects which, subject to future investment decisions, may be commercialised through the Saturn Banks infrastructure. All its assets are co-owned 50:50 with its joint venture partner CalEnergy Resources (UK) Limited. Further details of its portfolio can be found at www.iog.co.uk.

Competent Person's Statement

In accordance with the AIM Note for Mining and Oil and Gas Companies, IOG discloses that Phil Cox, IOG's Head of Subsurface, is the qualified person that has reviewed the technical information contained in this document. He has an MSc in Geology from the Royal Holloway, University of London, is a fellow of the Geological Society and has over 23 years' of experience in the upstream oil and gas industry. Phil Cox consents to the inclusion of the information in the form and context in which it appears.

Chief Executive's Review

2022 Review

2022 saw IOG become the UK's newest gas producer, as Saturn Banks was safely brought onstream in mid-March. The IOG team's dedication, supported constructively by our joint venture partner CalEnergy Resources (UK) Limited (CER), turned the company from an unfunded concept into a low-carbon gas producer in just a few years.

From First Gas in March until year end, we delivered average gross production of 27.4 mmscfe/d, generating £79.6 million of revenue (£3.6 million of which was from condensate). Whilst EBITDAX of £63.1 million demonstrates our underlying profitability, the year was overshadowed by a number of operational and subsurface challenges which led to production, revenue and profitability being below our expectations. The full year loss of £18.7 million reflects the impact of £52.6 million of asset impairments following the very disappointing Southwark A2 well result.

FY 2022 Operating and Financial Summary

Operating	**Unit**	**FY 2022**	**FY 2021**
Annualised gross gas production	mmscf/d	21.0	Nil
Net gas sales	mmscf	3,444	Nil
Volume weighted average gas price	p/therm	201.4	N/A
Net condensate sales	MT	5,339	Nil
Average condensate price	$/MT	805	N/A
TRIR	per 200,000 hrs	3.6	3.5
Emissions intensity	kgCO e/boe	0.8	N/A
Financial			
Revenue	£m	79.6	nil
Opex	p/therm	24.0	N/A
Loss for the year	£m	(28.4)	(2.4)
EBITDAX	£m	63.1	(3.7)
Capex spend (net to IOG)	£m	56.8	59.1
Cash (excluding restricted)	£m	26.7	31.3
Net debt	£m	65.1	56.6
Basic EPS	£p	(5.4)	(0.4)
Adjusted EPS	£p	4.3	(0.4)

At IOG, the first gas milestone was always intended to be the start of a new era. The first fields were intended to deliver the operating cashflow to enable the company to grow and diversify its production portfolio and deliver shareholder returns. In that context, a combination of much lower reserves in Elgood, formation water production from Blythe H1 and the failure of the Southwark A2 well to produce at commercial rates has significantly impacted our position compared to expectations. However, together with our joint venture partner, we own a significant and strategic infrastructure position in an area where there are multiple undeveloped gas resources and we remain a production company with cashflow which we expect to be significantly enhanced in mid-2023 by the Blythe H2 well.

This combination of challenges culminated in a change of senior management in October 2022, with the highly experienced Dougie Scott arriving as COO, John Arthur becoming CFO and my appointment as CEO. Our immediate focus was to turn around near term operational performance and reduce operating costs. We are now reviewing our future plans against a rebaselined technical assessment of our reserves and resources, with a view to balancing cash generation and value creation. Given the operational challenges we have experienced over the past year, we are also ensuring that the lessons are learned and applied to future operations.

The management change gave us the opportunity to reset and improve the way we work. The skills and experience of the new leadership team are more suited to this early production phase of the business and to delivering further phases of development through the Saturn Banks system in a safe and efficient manner to drive returns. More fundamentally, we redefined our core IOG values: Safety, Integrity, Ownership, Performance, Ingenuity and Teamwork. This is reflected in a new Code of Conduct that sets out our working principles and the high standards we expect of each other.

As CEO, I believe it is vital that we lead by example in our key behaviours. This includes taking personal responsibility for all decisions and actions (not least on safety and environment); applying learnings for continued improvement; communicating clearly, openly and effectively; tackling issues proactively; and looking for creative improvement; communicating clearly, openly and effectively; tackling issues proactively and looking for creative solutions; and listening to and supporting our teammates. All with clear objectives in mind: more efficient operations, higher production and lower costs.

In the UK context, our low carbon intensity domestic gas production strategy retains compelling logic. In 2021, the UK imported 62% of its gas consumption. Every molecule produced locally limits the UK's reliance on high carbon intensity liquefied natural gas (LNG) imports. Gas remains the UK's largest primary energy source, heating 85% of UK homes, generating around 40% of UK electricity (providing vital balance to intermittent renewable generation) and fuelling key industries. Under all forecast scenarios, gas will continue to play an indispensable role in the energy transition, at least to 2050, and Liquefied Natural Gas (LNG) has become increasingly critical to energy security. In that context, IOG's industry-leading 2022 Scope 1 and 2 emissions intensity of just 0.8 kgCO e/boe, compared to the 2021 UK North Sea average of 21.2 kgCO e/boe, gives us clear environmental differentiation, especially in comparison to imported LNG which can exceed 100 kgCO e/boe. We will continue to look for ways to minimise operating costs and emissions alike.

In 2022 we also witnessed several important market, regulatory and geopolitical developments. The year was overshadowed politically by the conflict in Ukraine. Beyond the manifest human tragedy of this war, it has had and will continue to have profound implications for European energy markets. It was an extraordinary year for gas markets, with UK day-ahead prices ranging from 10 p/therm (in May) to 450 p/therm (in August). We expect 2023 UK gas prices will remain volatile and above historical norms, if lower than our 2022 realised average of 201.4 p/therm. Such volatility can be challenging to manage, but we retain the same fundamental approach to our economic planning: to look through short-term noise and stress-test our investment decisions against a range of prudent through-cycle assumptions.

Although the Ukraine conflict brought renewed focus on energy security, counterintuitively, the post-pandemic commodity price spikes also fuelled fiscal changes that will likely weaken energy security. For the UK, maximising the value of domestic UK resources, ensuring greater energy security as an import-dependent market, and delivering the Net Zero journey requires a stable and balanced fiscal regime. The introduction, swiftly followed by the extension, of the Energy Profits Levy (EPL) presents clear risks to upstream investment and industry competitiveness. The 75% marginal tax rate, without price floors or allowances for smaller projects, is now effectively one of the world's most punitive fiscal regimes. While the ultimate amounts to be paid will depend on our production volumes, realised gas prices and the size and nature of future investments, these accounts reflect a 2.2 p/share value impact for IOG.

Post-Year End and 2023 Outlook

Lower than expected production following the Southwark A2 setback has created uncertainty over future cash flows. The new leadership team has been carefully assessing the Company's projected financial performance and continues to analyse options to best manage the capital structure in both the short and longer term. In that context, we have been working to deliver incremental improvements such as fixed cost reductions and increased oversight and assurance. We have also initiated a full technical review of the pre-development portfolio to ensure we allocate capital in the most effective way in future.

In February the IOG-CER joint venture sanctioned the Blythe H2 well. This is designed to significantly enhance current production rates, reduce water production into the Saturn Banks pipeline and minimise associated operating costs. It has a compelling economic and operational logic and can pay back rapidly, enabling us to boost cash flow from mid-2023.

Early in 2023, following a rigorous technical and commercial screening process, we submitted joint bids with our partner CER, under our Area of Mutual Interest Agreement, for nine SNS blocks across five licences in the 33rd UK Offshore Licensing Round. Licensing round acquisitions are an important, low entry-cost strategic tool with which we have had significant previous success. All the target licences are adjacent to existing Saturn Banks licences and contain discovered resources, with some containing redevelopment opportunities and others featuring near-field exploration potential. If successful, these applications could add tangible value to all of our gas hubs.

In February 2023, Fiona MacAulay, who has been Chair of IOG since December 2018 having first joined the Board in July 2018, confirmed that she will not stand for re-election as a director at the 2023 Annual General Meeting. Esa Ikaheimonen will replace Fiona as Chair initially on an interim basis, bringing his deep understanding of the Company, a wealth of industry expertise and extensive financial and commercial experience to the role. We have initiated a process to bring in two further non-executive directors to further strengthen the Board.

Finally, I would like to reiterate my thanks to everyone in the IOG team, who have been working incredibly hard in difficult circumstances. Equally, I thank our very constructive joint venture partner CER and all our Duty Holders and contractors, as well as all our regulators at NSTA, the newly inaugurated Department for Energy Security and Net Zero, OPRED and UK HSE, for working with us on Saturn Banks. Finally, my sincere thanks goes to all our investors for their support through this turbulent period as we look towards the next stage of the IOG journey, building production resilience and new growth across the portfolio.

Rupert Newall
Chief Executive Officer
15 March 2023

Operational Update

Saturn Banks Development and Production Assets

Blythe (P1736) and Elgood (P2260)

The Blythe platform is a monopile normally unmanned installation (NUI) with one well, H1, drilled and in production. The Elgood field has one subsea well installed, tied back subsea to the Blythe platform via a 6" connection and umbilical. The Blythe platform has a 12" pipeline tied into the 24" Saturn Banks Pipeline System (SBPS) 29km offshore via a subsea T-piece. From here the gas is transported into the Saturn Banks Reception Facilities (SBRF) at Bacton. Following completion of the SBRF refurbishment in the early part of the year, the Blythe and Elgood fields were brought onstream on the 13th and 15th March 2022 respectively.

Average gas production from Blythe and Elgood from First Gas in March to the end of the year, was 27.4 mmscf/d. Gross condensate sales from both fields amounted to 1067.9 metric tonnes over the same period.

Production Efficiency, which includes planned and unplanned losses, for Blythe and Elgood on a combined average basis was 58.6% from First Gas to the end of 2022. Unplanned platform outages downtime in 2022 resulted from various factors, including a mono-ethylene glycol (MEG, hydrate inhibitor) injection fault and generator trips. In response, the Company undertook production resilience measures, including enhanced helicopter and vessel access to enable faster offshore restarts. Onshore, modification to a recycle compressor in the Bacton terminal's condensate stabilisation unit also caused a one-week production outage in May 2022.

Early in Q3 2022, formation water started to arrive onshore via the SBPS. Analysis indicated that a sub-seismic resolution natural reservoir fracture encountered during Blythe H1 development drilling was the most likely source of this. Salinity levels of the formation water exceeded the maximum allowable for processing at Bacton and thus necessitated an alternating regime of batch slugcatcher liquid letdowns alongside other streams entering the terminal. This revised liquid management regime constrained production levels.

Over a four-week period in October and November 2022, Blythe and Elgood were shut in to allow the Southwark leg of the Saturn Bank Pipeline system to be connected to the 24" pipeline to SBRF via the subsea T-piece. On production restart, Blythe flowed as expected, however it was not possible to sustain production from Elgood. Analysis indicated that the Elgood well would flow in the event the pipeline was dewatered.

Blythe (P1736)

Prior to production, gross 1P/2P/3P management estimated Blythe gas reserves were 25.9/43.3/56.9 billion cubic feet equivalent (BCFE, where condensate is converted into gas equivalent at 5.8 bbl/mcf). In Q4, technical analysis of production and reservoir pressure data from the first six months of Blythe H1 production indicated that the well is located in a reservoir compartment which is materially baffled from the central and northwest areas of the field. It was assessed at the time that the H1 well would ultimately recover an estimated 29 BCF of gas.

A second Blythe production well, H2, has been planned in order to enhance production levels and maximise ultimate recovery of Blythe reserves, as well as to reduce production of formation water into the pipeline. In February 2023, the Blythe H2 well was sanctioned with the intention to be drilled and completed over Q1-2 2023.

Blythe FY2022 1P and 2P reserve estimates shown in the reserves summary table above represent a modest increase on FY2021 estimates, factoring in 2022 production of 4.1 BCFE.

The 1P case assumes production only from the H1 well, as H2 was not sanctioned at year end, and the 2P case assumes production from H1 and H2, which was sanctioned in February 2023.

Elgood (P2260)

Prior to production, gross 1P/2P/3P management estimated Elgood gas reserves were 9.6/14.1/18.3 BCFE. In Q4, technical analysis of the production and reservoir pressure data from the first six months of production indicated that the flow rate was declining faster than anticipated given the pre-production reserve estimate. This analysis indicated that gas is not flowing across the NW-SE oriented intra-field fault to the wellbore as expected. On that basis the most likely ultimate recovery from the field was further revised as shown in the reserves table above.

During 2022, 4.1 BCFE was produced from Elgood. As at the date of this report, the Elgood field is shut-in, with further production expected when a reduction in pipeline export pressure is realised, in the following scenarios:

1. The SBPS has been dewatered, after which it could be produced cyclically

2. Onshore compression has been introduced

The 1P case assumes 0.4 BCFE production post-dewatering and the 2P case assumes 0.4 BCFE post dewatering and a further 1.8 BCFE post-compression.

Southwark (P1915)

Following the spudding of the A1 development well at the end of 2021, in January 2022 drilling was temporarily suspended due to damaged leg cross members caused by serious scour issues around the jack-up spud cans. The jack up rig was demobilised and repaired while the spud can location at the platform was remediated by installing rock pads. The rig was re-mobilised and operations on A1 recommenced in April. After drilling the initial section of A1, the rig was skidded to drill the A2 well as planned before resuming A1.

In Q2 2022, the 6km 24" extension of the SBPS to the Southwark platform was safely and successfully installed by the Seven Borealis S-lay vessel. This was subsequently hooked up to the in situ 24" line in Q4.

On A1 extensive drilling fluid losses were encountered in the Bunter Sandstone Formation. The 9-5/8"' casing was run in an attempt to isolate the loss zone, however this was unsuccessful as further losses were encountered on drilling out of the 9-5/8" casing shoe into the Bunter Shale Formation. After due consultation, the JV elected to suspend the A1 well in order to evaluate and develop an appropriate remediation plan for A1.

After an equipment rig-up period, stimulation operations on A2 commenced in November and continued through to the year end. In total, six hydraulic fractures were deployed into the reservoir. The well was cleaned up via the temporary well test separator. The clean-up phase saw lower than expected gas rates and high rates of associated water, indicating a connection to the active aquifer. A production logging tool was then run which provided input data for remediation via isolation of water producing zones. This remediation reduced water production from 1500 bbls/d to an average rate of 380 bbl/d, however, stabilised gas rates were limited to 2.5 mmscf/d, at a flowing wellhead pressure of 1186 psi. These rates did not justify hooking up the A2 well for production and so the well was suspended in order to conduct a full analysis to ascertain future production options.

Following the A2 result, the JV made the decision to delay the re-entry into A1 pending further analysis. A1 remained suspended and the rig was moved to Blythe to drill the H2 well.

The A1 well is intended to penetrate the western panel of the Southwark reservoir and produce through deploying five hydraulic fracture stimulations. This area of the field has greater well control from the Southwark discovery well (49/21-8A). The A1 well is to be landed close to the discovery well, thus providing more accuracy in reservoir entry depth, reservoir thickness and free water level at that location.

A multi-disciplinary task force involving external experts has commenced a full review to ascertain the causes of the results encountered on A2 and identify how any lessons learned can be implemented on A1. This review may inform a further revision of the estimated reserves range. Pending that review, the current estimated reserves range shown in the reserves table above reflects the uncertainty following A2 as to the recoverability of commercial gas volumes from both the A1 and A2 wells. The 1P case assumes no production is possible from the field and the 2P case assumes production from the A1 well only, based on a limited stimulation scenario, with no production from the A2 well.

Pre-Development Assets (PDAs)

Central Hub: Nailsworth (P130 & P2342) and Elland (P039) discoveries

The fully-owned subsidiary IOG UK Limited (IOGUKL) has a 50% working interest and is operator of the P130 and P2342 licences, which contain the Nailsworth gas discovery, and the P039 licence, which contains the Elland discovery.

Nailsworth is a three-way dip and fault sealed structure directly north of the Vulcan field (which produced 665 BCF between 1988 and 2018). Four exploration and appraisal wells have been drilled on the Nailsworth structure, confirming a gas-water contact (GWC) of -7,657ft TVDSS. The Company has reprocessed 3D seismic data to Pre-Stack Depth Migration (PSDM) standard and completed new static and dynamic reservoir modelling of the field.

In the FY2022 reserves and resources review, the Nailsworth and Elland gas fields, which are envisaged to be part of a Central Hub development in the area north of Southwark, have been reclassified from the Reserves category Justified for Development to the Contingent Resources category Development Pending. This classification change is considered currently more appropriate given the evolution in development plans and pre-Final Investment Decision (FID) status. Following an FID, the fields would be expected to be reclassified back into reserves.

The estimated contingent resources range for Nailsworth has been revised to 1C/2C/3C 48.5/84.9/140.2 BCFE. This follows a full subsurface uncertainty analysis which included updates to the static and dynamic models. The post-A2 detailed technical review of Southwark may also have implications for the Nailsworth estimated resource range. The volumetric estimates on the Elland gas field have not changed.

Evaluation of the Nailsworth and wider Central Hub export route and host options identified the preferred option as the Southwark platform 19km to the southeast, with onward export via Saturn Bank Pipeline System. This is considered to have the strongest operational and commercial synergies and lowest expected emissions impact. The optimal development of the Nailsworth reservoir is likely to be via hydraulically stimulated production wells, which could be phased based on well performance.

Development concept engineering work, working closely with the JV partner CER, has then considered a wide range of potential development concept options for Nailsworth and the other Central Hub fields. This evaluation took into account the bathymetry of the area, designated export route and minimisation of environmental impact. This may justify some pre-investment to enable future connection of the incremental subsea infrastructure for the other Central Hub fields. The concept engineering and subsurface evaluation basis was collated into a Concept Select Report (CSR) and submitted to the NSTA.

The key scopes within the planned Nailsworth Front-End Engineering and Design (FEED) cover:

- engineering design of the subsea infrastructure including the export pipeline to the Southwark platform
- design and configuration of the controls (power, hydraulics and chemical supply) for the subsea wells
- flow assurance on the production fluids to confirm the sizing of the pipeline for Nailsworth and the consideration through the asset life incorporating the other central hub fields and compression

The Nailsworth FEED bid submissions were under evaluation at the time of this report. In parallel, a Field Development Plan (FDP) and Environmental Statement are being worked on in preparation for an eventual JV FID on Nailsworth, as part of the wider Central Hub.

As previously disclosed, the Elland field has a suspended well 49/21-10A on it. On acquisition from the previous owners, the Company took on the liability to permanently plug and abandon this well. This work is planned for the first half of 2023, at an estimated gross cost of £0.8 million (£0.4 million net to IOG).

Potential Southern Hub: Abbeydale and Orrell (part) discoveries, Kelham North, Kelham Central, Thornbridge and Thornbridge Deep prospects (P2442)

IOG holds a 50% working interest in Licence P2442, as operator, via its fully-owned subsidiary IOG North Sea Limited (IOGNSL). The licence contains the Abbeydale gas discovery, part of the Orrell discovery, and the Kelham North, Kelham Central, Thornbridge and Thornbridge Deep prospects. The firm work programme commitment to reprocess 150 km² of seismic data within two years was completed in early 2021. An appraisal well is to be drilled on the licence by the end of the Initial Term, which is currently 30 September 2023. In early 2023, in light of unexpected delays to the Phase 1 development drilling programme, IOGNSL formally requested a six-month extension to the Initial Term of Licence P2442 so that the appraisal well could be drilled within the appropriate licence term. The extension request is under consideration by the NSTA at the time of this report.

Interpretation of the reprocessed dataset enhanced the Company's view of the resource potential across the licence. The deterministic management estimate of gross 1C/2C/3C contingent resources at Abbeydale remained at 19/23/25 BCFE. The tight resource range reflects a well-defined structure, constrained by well data from the 51/13a-13 appraisal well.

Technical work also included a more sophisticated depth conversion and mapping work programme to better capture the Gross Rock Volume uncertainty range of the identified structures, further evaluation of the existing adjacent well stock and an improved understanding of rock quality. This identified several further prospects and leads on the licence. To the immediate north of Abbeydale lies the formerly producing Camelot Complex, comprising several fields developed and produced by Mobil (and later Perenco). The Kelham North prospect is a previously unmapped, distinct structural closure within the Cador field, which was part of the Camelot Complex. Similarly, mapping of the Kelham Central prospect, and reconciliation with production volumes from Camelot Central, suggest an unconnected volume from an undrained structure.

The seismic reinterpretation combined with available production data has been used to generate the current management estimated gross Low/Mid/High contingent gas resources of 34/46/58 BCFE in Kelham North and 11/16/22 BCFE in Kelham Central, both with a 72% Geological Chance of success (GCoS). The planned appraisal well and side-track is intended to confirm these resource ranges in the structures.

If successfully appraised, these assets would form the basis of a new Southern Hub development that would include a subsea tie-back of the Abbeydale discovery to gas gathering infrastructure tied directly into the Saturn Banks Pipeline System. In the Company's view, successful appraisal would significantly de-risk the other discoveries and prospects in the P2442 licence, enhancing the commercial potential of the area and providing add-on development opportunities for the potential Southern Hub.

Thornbridge and Thornbridge Deep are two further prospects on the P2442 licence, lying to the northwest of Abbeydale. Subject to successful exploration, these structures may provide further resource additions to the potential Southern Hub, as detailed in the prospective resources table above. A further discovery, which the Company has named Orrell, lies partly on the P2442 licence, extending over its northern limit into an unlicensed area. Management estimated prospective resources on licence were revised marginally down in the FY2022 technical review to Low/Mid/High 11/16/22 BCFE. Subject to further technical assessment and successful appraisal of the Kelham North and Kelham Central structures, Orrell could potentially become part of a Southern Hub development via a single well subsea tie-back to an unmanned host platform.

Potential Northern Hub: Goddard discovery, Goddard Flank structures, Southsea prospect (P2438)

IOGNSL also has a 50% working interest and is operator of Licence P2438, which contains the Goddard field, an undeveloped gas discovery. In light of the relative maturity of Goddard's contingent resources, and to improve structural imaging of the field as much as possible, further reprocessing to PSDM and reinterpretation of 3D seismic data over the Goddard area was undertaken in 2020-21. Additional seismic mapping was then carried out that incorporated further structural analysis of the PSDM seismic data, resulting in clearer definition of the greater Goddard area, a better understanding of lateral velocity variation across the field allowing an enhanced depth conversion methodology. There is now also better definition of main field bounding faults and possible intra-field faults which is key to optimal development of the field. This work resulted in management estimated contingent resources for the main Goddard structure of 52/115/169 BCFE. Further mapping work also resulted in management estimated prospective resources in the Goddard flank structures to Low/Mid/High 16/27/42 BCFE and 30/50/73 BCFE, with 71% GCoS in each case. The management estimated contingent and prospective resources range for Goddard, the Goddard Flanks and Southsea remained the same in the FY2022 technical review.

An appraisal well is to be drilled on the licence by the end of the Initial Term, which is currently 30 September 2023. The PSDM has also been used to optimally locate the planned appraisal well to be drilled approximately 4 kilometres away from the Goddard discovery. The well is intended to test the full range of possible gas-water contacts resulting in greater certainty of the Gas-Initially-in-Place (GIIP) within the Goddard structure and to de-risk the Goddard Flank structures. The results of the appraisal well will enable the Company to determine the optimum field development scenario, including well count, to maximise the return on investment from commercialisation.

On 3 May 2022, the Initial Term of Licence P2438 (Goddard) was extended by 12 months to 30 September 2023, to allow the drilling and completion of the Goddard appraisal well within the appropriate licence term. In early 2023, in light of unexpected delays to the Phase 1 development drilling programme, IOGNSL formally requested a six-month extension to the Initial Term of Licence P2438 so that the drilling and completion of the appraisal well could be undertaken within the appropriate licence term. The extension request is under consideration by the NSTA at the time of this report.

Seismic reinterpretation has also identified the Southsea prospect within Licence P2438 close to the south-east of Goddard, with gross management estimated prospective resources of Low/Mid/High 13/31/76 BCF and a 48% GCOS. The results of the Goddard appraisal well may inform an update to these estimates.

Grafton and Panther (P2589)

The P2589 licence was awarded in the 32nd Licensing Round and formally commenced on 1 December 2020. The licence commitment to reprocess 79km2 of seismic data within three years has been completed. Under the licence, a decision must be taken in 2023 either to drill an appraisal well on the licence by 30 November 2025 or relinquish the licence.

The licence contains the Grafton discovery, for which management's initially estimated gross 1C/2C/3C contingent gas resources of 24/35/46 BCFE has not changed to date. IOG has completed a programme of 3D seismic reprocessing to PSDM standard, from which data is currently being interpreted. This includes a more sophisticated depth conversion and mapping work programme than previously undertaken and should enable a clearer view of the commercial potential across the licence.

The licence also contains the Panther discovery which lies approximately 5km northwest of Elland. Subject to interpretation of reprocessed seismic, could potentially form part of the Central Hub development. Pending reinterpretation of reprocessed seismic, management's estimate of gross 1C/2C/3C contingent gas resources remains at 38/46/55 BCFE.

Business Development

The Company takes a systematic focused approach to screening opportunities to enhance its asset portfolio and further develop the business. All opportunities are evaluated in terms of fundamental value, potential return, materiality and synergy with the existing portfolio, ranked alongside the Company's existing assets. The fundamental purpose is to generate enhanced stakeholder value over time, rather than simply to build a bigger business.

There are several different types of possible acquisition opportunities continually evaluated by management, each with potential to generate operating and economic synergies with the existing portfolio. The first of these is licensing activity, whether in formal licence rounds or by separation engagement with the OGA, which offers a well-established and low-cost path to adding suitable incremental assets. The Company has an extensive track record of successful licence round applications, including the 27th, 30th and 32nd UK Offshore Licensing Rounds. However, licensing rounds are relatively infrequent and not guaranteed to include the most attractive licences, therefore out-of-round applications and expressions of interest are also considered valid approaches to acquiring suitable unlicensed acreage.

In addition, there may be at any given time potential acquisitions from other licensees and operators who may be interested in either selling or farming-out assets at various stages of maturity, including appraisal, development or also previously developed shut-in or decommissioned assets. The Company undertakes a systematic ongoing review of all such opportunities to ensure it can prioritise those it may wish to pursue. Furthermore, the Company also discusses potential gas transportation tariffing opportunities and engages with parties who may be seeking access to export infrastructure as part of their own development planning.

In January 2023, after a rigorous technical and commercial screening process, IOG and its joint venture (JV) partner CalEnergy Resources (UK) Limited (CER) applied for nine Southern North Sea blocks across five licences in the 33rd UK Offshore Licensing Round. All applications are adjacent to existing Saturn Banks JV licences. All on a 50:50 IOG-CER basis with IOG as operator, as per the JV's Area of Mutual Interest agreement. These applications exhibit strong synergies with the Saturn Banks portfolio and infrastructure: all licences would fit clearly within IOG's area plan. Each licence contains discovered resources that could be added to development hubs. Some have field redevelopment opportunities and some have near-field exploration potential. The UK North Sea Transition Authority is expected to start making the first 33rd Round licence awards in Q2 2023.

Key Performance Indicators

The Group's main business is the acquisition, development and production of gas reserves and resources in a safe, efficient and environmentally responsible manner. This is undertaken by assembling and managing a carefully selected portfolio of licence interests containing a range of prospective, contingent and proven reserves, working these up from a technical perspective, planning, designing and executing appropriate appraisal, pre-development and development activities and ensuring effective ongoing production operations.

The Company monitors its performance against its primary HSE and ESG KPIs, which are the Total Recordable Incident Rate (Lost Time Incidents per 200,000 manhours worked) and Scope 1 and 2 emissions and emissions intensity. Other HSE performance indicators include securing all relevant environmental permits, consent and approvals, and maintaining a verified Environmental Management System.

The main operational KPIs include production rates as well as the total reserves and resources in the portfolio. Other operational performance indicators include successfully meeting all licence commitments relating to the Company's asset portfolio during the year, maintaining effective relationships at all levels with JV partners in compliance with Joint Operating Agreements (JOAs), operating within appropriate governance and HR policies, ensuring the Company has adequate in-house capability to manage its operations and third-party providers, and ensuring all corporate legal obligations are met.

Financial performance is tracked against established metrics and budgets which are set according to carefully assessed cost estimates and the availability of funds, whether raised from capital providers or delivered from operations, with the overriding objective of creating value per share. The main financial KPIs include unit operating cost i.e. opex (measured either in the standard industry metric of US dollars per barrel of oil equivalent to ensure comparability or more relevantly to IOG in pence per therm), operating cash flow and net debt. Financial performance indicators also include maintaining full compliance with terms of debt facilities, maintaining constructive relationships with debt providers and equity investors, being adequately resourced for all corporate and JV-related financial matters, maintaining appropriate fit-for-purpose finance systems, delivering approved annual budgets and adhering to updated financial and corporate operating policies.

Insurance

The Group insures the risks it considers appropriate and proportionate for its needs and circumstances, including any risks that it has an obligation to insure against. However, it may elect not to put insurance in place at certain times for certain risks, for example due to high premium costs or extremely low probability risks. During 2021 the Group put in place insurance coverage for both construction and operational energy packages, covering Operators Extra Expense (OEE) during drilling activities, physical loss/damage, third party liability and OPOL in accordance with market standards. This insurance coverage and associated limits were in line with its energy sector peer group.

Principal Risks and Uncertainties

The Company seeks to generate shareholder returns by developing and producing its portfolio of offshore gas assets. This primarily entails construction and installation of production, transportation and processing infrastructure and drilling of production wells. These activities carry a number of associated financial, operational, regulatory, legal, commercial, human resource, HSE and sustainability related risks and uncertainties. The most pertinent corporate risks and associated mitigations are set out below.

Risk	Mitigation
Poor strategic decisions	• Annual review of business plan & objectives • Regular review of progress against objectives • Regular lessons learned reviews • Match Corporate Scorecard to business plan • Regular review of organic investments and assumptions • Regular review of M&A criteria & targets within strategic boundaries
Corporate governance deficiency	• Regular review of legislation and gap analysis with internal compliance policies • Annual training on corporate policies & procedures, covering Financial Operations, Anti-Bribery & Corruption, Travel & Expenses, Sustainability, and Insider Trading • Tender Committee meetings to ensure policy compliance on contracting
Undervalued market capitalisation	• Ensure company strategy and progress presented as effectively as possible in public materials • Continually engage with and present to existing and prospective investors where possible • Maintain defence planning with appropriate advisors
Negative cash flow	• Develop multiple business scenarios to determine cash flow restrictions • Develop cost reduction action plans • Develop additional funding options
Inability to repay or refinance bond and/or comply with covenants	• Close monitoring of liquidity position and cash flow projections to manage exposures • Tight cost control and working capital management • Regular review of potential financing options to ensure state of preparedness

	preparedness • Regular engagement with the Company's debt providers and advisors • Maintain access to equity markets via AIM listing
Reduction or loss of reserves	• Implement rigorous reserve and resource range assessment process • Use third-party technical verification & peer reviews • Use full reserves & profile range for project economics • Accurate history matching to understand reservoir performance & improve forecasts • Ensure highly competent technical team • Develop active lessons learned data base
Reduction or loss of production	• Monthly reviews of all key topics (HSE, maintenance, integrity, costs) • Production loss and improvement process • Robust oversight of duty holder via assurance plans for production operations & pipeline management • Deliver incremental production plans (e.g. Blythe H2) • Add support for Production Asset Manager • Detailed reviews of fixed opex and G&A
Underperformance of projects	• Ensure project has clear business objectives • Ensure project gate process is followed • Regularly review economics, subsurface, engineering and designs • Ensure project risks & mitigations, cost estimates & schedule are fully understood • Regular peer reviews and economic stress tests • Maintain strong development team competencies and ensure clear project ownership
Saturn Banks Pipeline System failure	• Duty holder monthly reviews and surveillance on key topics (HSE, reliability, maintenance and integrity) • Robust oversight of duty holder through assurance plans for production operations and pipeline management
Inability to attract and retain personnel with the right skills and experience	• Maintain a clear, credible strategy to build a sustainable, profitable and attractive business • Identify key individuals required to deliver the strategy effectively • Ensure competitive remuneration packages and professional development plans are in place
Loss of licences and/or regulatory licence to operate	• Robust oversight of all areas of project delivery • Maintain resources, processes, competencies to deliver licence obligations • Regular interaction with NSTA, BEIS/OPRED & HSE at all levels • Set realistic expectations with regulators • Follow all NSTA guidance • Compelling case & timely application for any license extensions or variations • Timely licence fee/levy payments • Maintain robust licence commitments register
Government energy, licensing or fiscal policy changes	• Maintain a low-cost business model • Maintain a low-carbon intensity business and continue to offset as necessary for Scope 1 & 2 Net Zero status • Engage with government and industry bodies to demonstrate company's contribution to UK energy
Gas price volatility	• Short term price fixing with offtaker • Maintain a low-cost business model • Continue to track gas market trends and analysis • Continue to take advice from gas market analysts

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Finance Review

Following First Gas in March 2022, the Company moved into a revenue generation phase of its development. Total revenue generated in the year, before sales deductions, was £79.6 million, of which £76.0 million related to gas sales and £3.6 million related to condensate sales. Total revenue after sales deductions was £75.4 million. Cost of sales and £3.6 million related to condensate sales. Total revenue after sales deductions was £75.4 million. Cost of sales totalled £23.6 million consisting of £10.1 million of operating running costs, depletion of £13.2 million and other operating expenditure of £0.4 million, offset by an increase in inventories of £40,000. Gross unit operating costs (excluding one-off and exceptional items) for the period were therefore 24.0 p/therm. This resulted in a gross profit of £51.8 million.

Despite the commencement of production and initial revenues during the year, the disappointing result from the Southwark A2 well and consequent downward revision in reserves at Southwark, Nailsworth and Elland resulted in a £51.0 million impairment. This, coupled with the £11.4 million deferred tax liability due to the Energy Profits Levy which was introduced during 2022, contributed to a full-year net loss after tax of £28.4 million.

The Company ended the year with an unrestricted cash balance of £26.7 million (2021: £31.3 million) plus £5.7 million of restricted cash (2021: £3.4 million), £2.6 million of which is the minimum holding of Bond interest in the DSRA and £3.1 million of which is decommissioning security. Group net debt at the end of the year was £65.1 million (2021: £56.6 million) (see note 18).

The €100 million bond (see below) and £11.6 million long-term, unsecured, non-interest-bearing Loan Note Instrument, convertible at 19p into 60,872,631 Ordinary Shares, both remained in place, with maturity dates in September 2024.

Income Statement

The Group made a loss for the year of £28.4 million (2021: £2.4 million loss) after asset impairments of £51.0 million.

Gas revenues for 2022 were £76.0 million (2021: £nil) and condensate revenues were £3.6 million (2021: £nil). Net gas revenues are £71.8 million (2021: £nil) inclusive of £4.2 million of sales deductions (2021: £nil). Total cost of sales was £23.6 million, consisting of operating expenditure (opex) of £10.1 million (2021: £nil), depletion of £13.2 million (2021: £nil), £0.4 million of other operating costs offset by an increase in inventory of £40,000. Accrued opex in the period included £8.2 million of production opex and £1.9 million of onshore tariffs and SBRF operating costs, which equated to gross unit operating costs (excluding one-off and exceptional items) of 24.0 p/therm. Cash opex was 13.9 p/therm, as the Group looked to manage the produced water onshore and identify lower cost disposal routes. This resulted in a gross profit of £51.8 million.

Operating loss for the period of £6.0 million includes £1.9 million of administration expenses, £51.0 million of impairment, £0.2 million of project, pre-licence and exploration expenses, and £4.7 million FX loss.

Reduction in 2P reserves over the Southwark development resulted in a £43.4 million impairment (2021: £0.9 million). The Nailsworth and Elland gas fields, which are envisaged to be part of a Central Hub development north of Southwark, have been reclassified as 2C contingent resources resulting in a write down of £7.6 million (2021: £nil). Net administration expenses of £1.9 million (2021: £2.1 million) reflect a lean corporate operation and the allocation of a proportion of overheads to project assets.

The foreign exchange loss of £4.7million (2020: £3.4 million gain) reflects realised and unrealised foreign exchange movements predominantly on the EUR denominated Bond and the USD denominated rig contract recognised under lease liabilities.

The total interest charged to the income statement was £11.1 million (2021: £3.1 million). The increase of £8.0 million was mainly due to additional interest expensed in the year, after capitalisation to qualifying assets, on the bonds of £6.9 million (2021: £nil). The Bond interest attributable to bringing capital projects on stream was capitalised in line with Company's accounting policy. After the start of production in March 2022, the Bond interest is being expensed. This resulted in a loss before taxation of £17.1 million.

The Group recognised a deferred tax liability of £11.4 million in 2022 following the introduction of an Energy Profits Levy (EPL) on the UK ring fence profits of oil and gas producers with effect from 26 May 2022 and reflects the exclusion of investment in the UK North Sea prior to this date contained within the legislation. The Group therefore recognised a loss after tax of £28.4 million (2021: £2.4 million).

On this basis, earning per share (EPS) were minus 5.4p. Adjusted EPS, removing the impact of the asset impairments, were 4.3p.

Statement of financial position

Property, Plant and Equipment (PPE) oil and gas assets increased to £149.8 million (2021: £138.8 million) during the year, representing capital expenditure activities on the Saturn Banks Project assets as well as capitalisation of the right of use of leased assets over their lease term under IFRS 16 and an increase in the decommissioning provision recognised against the assets, partially offset by depletion of the producing assets and the impairment of the Southwark field.

Total assets increased to £206.5 million (2021: £181.1 million), including cash resources of £32.4 million (2021: £34.7 million) of which £5.7 million is restricted (2021: £3.4 million).

Total liabilities have increased to £203.9 million (2021: £151.0 million), with the Bond representing £ 87.6 million (2021: £82.4 million). Current liabilities include trade payables of £11.1 million (2021: £7.7 million), lease liabilities of £15.8 million (2021: £11.1 million), accruals and operator advance accounts of £36.9 million (2021: £23.7 million) given the high volume of work as the Phase 1 development progressed, and deferred considerations in relation to acquisitions of £0.8 million (2021: £0.6 million).

Under IFRS 16, IOG is responsible for capitalising 100% of the lease cost of its rig contract as well as certain vessel contracts, to its statement of financial position. Based on the minimum contract durations and day-rates, IOG has therefore recognised £12.2 million in Property, Plant and Equipment (PP&E). IFRS 16 also requires recognition of the lease liability for future payment obligations and interest on lease liabilities in the income statement over the lease term. Based on the minimum contract duration and day-rate, IOG has therefore recognised £15.8 million (net liability after payments) in lease liabilities.

Non-current liabilities include decommissioning provisions net to IOG of £29.8 million (2021: £15.8 million), including Saturn Banks Pipeline decommissioning provision of £4.4 million (2021: £0.1 million), Saturn Banks Reception Facilities decommissioning provision of £2.8 million and the addition of further Phase 1 infrastructure of £22.5 million (see note 17). Non-current liabilities also include long-term lease liabilities recognised under IFRS 16 of £1.3 million (2021 £11.1 million) related to the Saturn Banks Pipeline land lease and office leases, and a deferred tax liability recognised following the introduction of the EPL of £11.4 million (2021: £nil). This resulted in net assets of £2.6 million (2021: £30.2 million), with the decrease predominantly driven by the impairment on Southwark during the year.

The Group ended the year with a net debt position of £65.1 million (2021: £56.6 million), primarily driven by the ongoing expenditure on the Phase 1 assets. Net debt is defined as total loans, primarily the EUR denominated Bond, less restricted cash and cash equivalents.

Cash Flow

Net cash inflows of £71.8 million (2021: £20.0 million inflow) from operations, net cash outflow of £49.6 million (2021: £3.6 million inflow) used in investing activities and net cash outflow of £27.2 million (2021: £8.2 million) used in financing resulted in a cash and equivalents position of £26.7 million at year end (2021: £31.3 million). The increase of £71.8 million for cash generated by operations reflects the transition to a production phase for the Company. At the end of the year £5.7 million (2021: £3.4 million) of funds were also held as restricted cash in the DSRA and as decommissioning security.

The Directors do not recommend payment of a dividend (2021: nil).

€100 million Bond

The Group's €100 million 5-year senior secured Bond was issued in 2019 in the name of Independent Oil and Gas plc (the former name for the Company) to a range of institutional investors across the Nordic region, Europe, UK and Asia. The bond has a bullet repayment structure, with a maturity date of 20 September 2024, and an interest rate, payable quarterly, of 9.5 per cent per annum over the three-month EURIBOR rate. The Bond has a senior secured position over the Group's licences and infrastructure assets, as well as any further licence in which the Group takes an ownership interest during the tenure of the Bond. Permitted use of funds are Phase 1 capital expenditure, financing costs and general corporate purposes.

The Bond has been listed since December 2019 on the Oslo Børs with the ISIN NO0010863236. It is callable from September 2022, with an initial call premium of 50% of the coupon (i.e. repayable at a cost of €104.75 million (£88 million) if the three month EURIBOR is at zero or lower), declining by 10% every six months thereafter. The Bond documentation includes the option, subject to conditions and investor appetite, to issue additional amounts up to a maximum aggregate of €30 million (£25.2 million) ("Tap Issues"). Tap Issues carry identical terms to the initial €100 million issue but may be issued at different prices.

Commodity Risk Management Policy

The fundamental principle of the Group's commodity risk management policy is to take a prudent approach to mitigating exposure to fluctuations in gas prices and/or currencies to best protect cash flows. The Group will enter into price fixing transactions only to manage genuine risks to cash flows, factoring in relevant economic data and reasonable projections of its production, costs and debt service profile, and never for the purposes of investment or speculation. Commodity and foreign exchange (FX) exposures are overseen by a Risk Management Committee (RMC) and decisions are taken by a quorum of this RMC, which must include the CFO (with a second Executive Director also required to approve transactions with a nominal value over a certain threshold).

Over certain months in 2022, the Group fixed month ahead gas prices under its gas sales agreement with BPGM, the designated gas offtaker, at a volume of 30,000 therms/day, as follows:

August 2022	310 p/therm
September 2022	444 p/therm
October 2022[1]	263 p/therm
December 2022	303 p/therm

At the current time, the Company expects to continue to fix prices for an appropriate proportion of its production with BPGM. Details of the risks arising from the Group's use of financial instruments can be found in Note 24 to the financial statements.

[1]October 2022 price fix was closed out mid-month in light of the requirement to temporarily suspend production in order depressurise the Saturn Banks Pipeline System at that time.

Funding & Liquidity

The financial statements of the Group are prepared on a going concern basis.

In undertaking a going concern review, the Directors have given careful consideration to the Group's financial projections prepared by management for the period to 31 March 2024 (the review period). The Directors have also considered significant known events beyond 31 March 2024. The projections reflect the Company's best estimate of expenditures and receipts for the period. The Directors have reviewed management's key assumptions on which these projections are based, including a downside price and other risking scenarios. The near-term cash forecasts are regularly updated and reviewed to enable continuous monitoring and management of the Group's cash flow and liquidity risk. The forecasts indicate that, including the expectation that the Company can amend capital commitments under some of its licences and taking into account other cost saving and capital management initiatives, the Group has sufficient capital resources for a period of 12 months from the date of approval of this annual report. The Group's debt matures in September 2024 and the forecasts currently show that the Group plans to refinance its debt.

As part of its analysis in making the going concern assumption, the Directors have considered the range of risks facing the business on an ongoing basis, as set out in the risk section of this Annual Report. The principal assumptions made in relation to the going concern assessment include the continued production from the Blythe H-1 well, the successful delivery of the Blythe H-2 well and subsequent gas production rates, the potential evolution of gas prices and potential future capital allocations on its operated assets in the UK Southern North Sea.

Following a disappointing result from the Southwark A2 well test and remediation programme, the Company, in conjunction with its joint venture partner CER, sanctioned the drilling of Blythe H-2, prioritising it ahead of Southwark A1 as a lower risk option. Gas rates from H2 are expected to initially be in the 30-40 mmscf/d range and the well is expected to be completed and producing within a period of approximately three months from the spud date of 5 March.

The Company takes regular external advice on gas price forecasts. The base case uses the forward curve for near-term gas prices. The average gas price used in the review period is 130p/therm. Since the end of 2022 gas prices have fallen over 20%. This sustained fall in gas price during the review period would result in a covenant breach in the interest cover ratio. At the year end forward curve prices, no covenant breach was forecast. The Company's €100 million bond is subject to covenants that are measured biannually in June and December, being minimum liquidity of €5 million, net debt to EBITDA of a maximum of 2.5x and interest cover of a minimum of 5.0x, based on measures as defined in the facility agreement. The ratio of net debt to EBITDA at 31 December 2022 was 1.1 times and interest cover was 7.0 times. In the downside case, where gas prices are assumed to be 50% below the current forward curve, both the leverage ratio and interest cover ratio are forecast to be breached. In the event that a covenant is breached, an extension or waiver of this covenant would need to be negotiated with the Bond Trustee. The Directors, taking into account their assessment of Bondholders' interests and given the Group would pass the minimum liquidity test, believe this would be likely to be achieved, however it is not guaranteed.

The forecast also indicates in the base case the Group would need to minimise capital expenditures in the review period. This may include the requirement to agree revised work programmes or licence commitments with the UK authorities on licences where the Group has capital commitments as well as discretionary expenditures. If the Company is unsuccessful in agreeing revised terms this may result in the need to raise alternative funds on whatever terms are available at the time.

The Directors have concluded that the uncertainty around the volatility of the gas price and future production levels from the Blythe H-2 well, as well as the need to take other mitigating actions described above represent a material uncertainty which may cast significant doubt on the Group's ability to continue as a going concern.

As a result of their review, and despite the aforementioned material uncertainty, the Directors have confidence in the Group's forecasts and have a reasonable expectation that the Group will continue in operational existence for the going concern review period and have therefore used the going concern basis in preparing these consolidated financial statements.

John Arthur
Chief Financial Officer
15 March 2023

Consolidated Statement of Comprehensive Income for the Year Ended 31 December 2022

	Notes	2022 £000	2021 £000
Revenue	3	**75,406**	-
Cost of Sales	4	**(23,641)**	-
Gross Profit		**51,765**	-
Administration expenses	5	**(1,879)**	(2,102)
Impairment of oil and gas properties	11	**(51,007)**	(865)
Project, pre-licence and exploration expenses		**(182)**	(104)
Foreign exchange (loss) / gain	5	**(4,736)**	3,440
Operating (Loss) / Profit	5	**(6,039)**	369
Finance expense	7	**(11,114)**	(3,066)
Finance income		**70**	29

Fair value gain		**-**	260
Loss on PPE disposal		**(4)**	-
Loss for the year before taxation		**(17,087)**	(2,408)
Taxation	8	**(11,362)**	-
Loss and total comprehensive loss for the year attributable to equity holders of the parent	9	**(28,449)**	(2,408)
Loss for the year per ordinary share - basic	9	**(5.4p)**	**(0.4p)**

The loss for the year of £28.4 million (2021: £2.4 million loss) arose from continuing operations.

The comparative amounts have been restated. For more details refer to note 1.

Consolidated and Company Statements of Changes in Equity for the Year Ended 31 December 2022

Group:	Share capital £000	Share premium £000	Share-based payment reserve £000	Accumulated losses £000	Total equity £000
At 1 January 2021	4,882	49,989	6,154	(38,227)	22,798
Loss for the year	-	-	-	(2,408)	(2,408)
Total comprehensive loss attributable to owners of the parent	-	-	-	(2,408)	(2,408)
Issue of shares	338	8,112			8,450
Share based payment charge	-	-	1,272	-	1,272
Expiry of share options	-	-	(20)	230	210
Exercise of share options	18	48	(210)	-	(144)
At 31 December 2021	5,238	58,149	7,196	(40,405)	30,178
Loss for the year	**-**	**-**	**-**	**(28,449)**	**(28,449)**
Total comprehensive loss attributable to owners of the parent	**-**	**-**	**-**	**(28,449)**	**(28,449)**
Share based payment charge	**-**	**-**	**826**	**-**	**826**
Expiry of share options	**-**	**-**	**(630)**	**630**	**-**
Exercise of share options	**12**	**24**	**(187)**	**187**	**36**
At 31 December 2022	**5,250**	**58,173**	**7,205**	**(68,037)**	**2,591**

Company:					
At 1 January 2021	4,882	49,989	6,154	(16,681)	44,344

Total comprehensive loss attributable to owners of the parent	-	-	-	(1,785)	(1,785)
Lapse of warrants	338	8,112	-	-	8,450
Share based payment charge	-	-	1,272	-	1,272
Expiry of share options	-	-	(20)	230	210
Exercise of share options	18	48	(210)	-	(144)
At 31 December 2021	5,238	58,149	7,196	(18,236)	52,347
Loss for the year	**-**	**-**	**-**	**(17,561)**	**(17,561))**
Total comprehensive loss attributable to owners of the parent	**-**	**-**	**-**	**(17,561)**	**(17,561)**
Issue of Share Capital	**-**	**-**	**-**	**-**	**-**
Share based payment charge	**-**	**-**	**826**	**-**	**826**
Expiry of share options	**-**	**-**	**(630)**	**630**	**-**
Exercise of share options	**12**	**24**	**(187)**	**187**	**36**
At 31 December 2022	**5,250**	**58,173**	**7,205**	**(34,980)**	**35,648**

The comparative amounts have been restated. For more details refer to note 1.

Consolidated Statement of Financial Position at 31 December 2022

	Notes	2022 £000	2021 £000
Non-current assets			
Intangible assets: exploration & evaluation	10	**3,161**	994
Intangible assets: other	10	**8**	75
Property, plant and equipment: development & production assets	11	**149,830**	138,805
Property, plant and equipment: other	11	**12,158**	4,872
Restricted Cash	21	**3,116**	-
		168,273	144,746
Current assets			
Inventories		**63**	-
Trade and other receivables	15	**8,906**	1,705
Restricted cash	21	**2,564**	3,429
Cash and cash equivalents	21	**26,693**	31,255
		38,226	36,389
Total assets		**206,499**	181,135
Current liabilities			
Trade and other payables	16	**(64,058)**	(43,468)
		(64,058)	(43,468)
Non-current liabilities			
Loans	17	**(97,437)**	(91,257)
Provisions	17	**(29,778)**	(15,837)
Other liabilities	17	**(1,273)**	(395)
Deferred tax liability	8	**(11,362)**	-
		(139,850)	(107,489)
Total liabilities		**(203,908)**	(150,957)
NET ASSETS		**2,591**	30,178

Capital and reserves			
Share capital	19	**5,250**	5,238
Share premium	19	**58,173**	58,149
Share-based payment reserve		**7,205**	7,196
Accumulated losses		**(68,037)**	(40,405)
		2,591	30,178

The comparative amounts have been restated. For more details refer to note 1.

The Notes below form part of these financial statements. The financial statements were approved and authorised for issue by the Board of Directors on 15 March 2023 and are signed on its behalf by:

Rupert Newall
Chief Executive Officer
15 March 2023

Company Statement of Financial Position at 31 December 2022

	Notes	2022 £000	2021 £000
Non-current assets			
Intangible assets	10	**8**	75
Property, plant and equipment: Other	11	**12,158**	4,872
Investments	13	**15,486**	15,486
Amounts due from subsidiaries	13	**104,457**	109,641
		132,109	130,074
Current assets			
Other receivables and prepayments	15	**568**	1,705
Restricted cash	21	**2,564**	2,066
Cash and cash equivalents	21	**26,693**	31,255
		29,825	35,026
Total assets		**161,934**	165,100
Current liabilities			
Trade and other payables	16	**(27,576)**	(21,101)
Non-current liabilities			
Loans	17	**(97,437)**	(91,257)
Other liabilities	17,23	**(1,273)**	(395)
		(98,710)	(91,652)
Total liabilities		**(126,286)**	(112,753)
NET ASSETS		**35,648**	52,347
Capital and reserves			
Share capital	19	**5,250**	5,238
Share premium	19	**58,173**	58,149
Share-based payment reserve		**7,205**	7,196
Accumulated losses		**(34,980)**	(18,236)
		35,648	52,347

The comparative amounts have been restated. For more details refer to note 1.

The Company has taken advantage of the exemption allowed under Section 408 of the Companies Act 2006 and has not presented its own Statement of Comprehensive Income in these financial statements. The Company loss for the year was £17.6 million (2021: restated £1.8 million loss).

The notes below form part of these financial statements.

The financial statements of IOG plc (Company number: 07434350) were approved and authorised for issue by the

Board of Directors on 15 March 2023 and are signed on its behalf by:

Rupert Newall
Chief Executive Officer
15 March 2023

Consolidated Cash Flow Statement for the Year Ended 31 December 2022

	Notes	**2022** **£000**	2021 £000
Loss for the year		**(28,449)**	(2,408)
Depreciation, depletion and amortisation	11	**13,050**	519
Exploration asset write off	10	**-**	865
Impairment of development & production assets	11	**51,007**	-
Share based payments		**817**	1,225
Fair value (gain) / loss		**-**	(260)
Interest received		**(70)**	(18)
Deferred tax charge	8	**11,362**	-
Finance expense	7	**11,114**	3,066
Effect of exchange rate changes on Bond		**4,620**	(5,901)
Movement in trade and other receivables		**(6,993)**	(732)
Movement in trade and other payables		**15,393**	23,641
Movement in Inventory		**(63)**	-
Net cash generated from operating activities		**71,788**	19,997
Investing activities			
Purchase of development & production assets		**(45,955)**	(58,269)
Purchase of exploration & evaluation assets		**(1,467)**	(506)
Purchase of intangible assets: other		**(39)**	(295)
Transfers (to) / from restricted cash		**(2,251)**	61,172
Interest received		**70**	18
Decrease in financial assets		**-**	1,520
Net cash (used in) / generated from investing activities		**(49,642)**	3,640
Financing activities			
Proceeds from issue of equity instruments of the Group		**36**	8,516
Lease liability payments	23	**(18,608)**	(12,307)
Interest paid		**(8,590)**	(4,441)
Other finance costs paid		**(11)**	-
Net cash used in financing activities		**(27,173)**	(8,232)
Net (decrease) / increase in cash and cash equivalents		**(5,027)**	15,405
Cash and cash equivalents at the beginning of the year		**31,255**	13,389
Effects of exchange rate changes on cash and cash equivalents		**465**	2,461
Cash and cash equivalents at end of year	21	**26,693**	31,255

The Notes below form part of these financial statements.

Company Cash Flow Statement for the Year Ended 31 December 2022

	Notes	**2022** **£000**	2021 £000
Loss for the year		**(17,561)**	(1,785)
Depreciation charges		**178**	519
Exploration asset write off		**-**	-
Share based payments		**817**	1,225
Fair value (gain) / loss			(260)

Fair value (gain) / loss		**-**	(260)
Interest received / (paid)		**(51)**	(5)
Finance expenses		**10,613**	3,280
Effect of exchange rate changes in Bond		**4,620**	(5,901)
Movement in trade and other receivables		**1,137**	761
Movement in trade and other payables		**17,579**	23,591
Net cash generated from operating activities		**17,332**	21,425
Investing activities			
Purchase of property, plant and equipment		**(45)**	(253)
Transfers (to) / from restricted cash		**(377)**	61,172
Loans to subsidiary undertakings		**(63,749)**	(60,247)
Repayments of loans from subsidiary undertakings		**68,933**	-
Interest received		**51**	5
Decrease in financial assets		**-**	1,520
Net cash generated from investing activities		**4,813**	2,198
Financing activities			
Proceeds from issue of equity instruments of the Company		**36**	8,516
Lease liability payments	23	**(18,608)**	(12,307)
Interest paid		**(8,590)**	(4,441)
Finance Other finance costs paid	7	**(11)**	-
Net cash used in financing activities		**(27,173)**	(8,232)
Net (decrease) / increase in cash and cash equivalents		**(5,028)**	15,391
Cash and cash equivalents at the beginning of the year		**31,255**	13,389
Effects of exchange rate changes on cash and cash Equivalents		**466**	2,475
Cash and cash equivalents at end of year	21	**26,693**	31,255

The Notes below form part of these financial statements

Notes forming part of the financial statements for the Year Ended 31 December 2022

1 Statement of Accounting Policies

General information

IOG plc (the "Company") is a public limited company incorporated and domiciled in England and Wales. The principal activities of the Group are the appraisal, development and production of gas assets, reserves and resources. The Group operates through subsidiary undertakings, details of which are set out in note 14 to the financial statements. The Group's area of activity is in the United Kingdom. The Group financial statements for the year ended 31 December 2022 consolidate the individual financial statements of the Company and its subsidiaries (together referred to as "the Group"). The registered office address is 6th Floor, 60 Gracechurch Street, London EC3V 0HR.

The Group's and Company's financial statements for the year ended 31 December 2022 were authorised for issue by the Board of Directors on 15 March 2023 and the balance sheets were signed on the Board's behalf by the CEO, Rupert Newall.

Basis of preparation

The principal accounting policies adopted in the preparation of the financial statements are set out below. The policies have been consistently applied to all years presented, unless otherwise stated. The consolidated financial statements are presented in GBP Sterling, which is also the functional currency of the Group. Amounts are rounded to the nearest thousand, unless otherwise stated.

These financial statements have been prepared in accordance with UK adopted International Accounting Standards and as applied in accordance with the provisions of the Companies Act 2006. On 31 December 2020, IFRS as adopted by the European Union at that date was brought into UK law and became UK-adopted international accounting standards, with future changes being subject to endorsement by the UK Endorsement Board. The preparation of financial statements in compliance with adopted IFRSs requires the use of certain critical accounting estimates. It also requires management to exercise judgment in applying the Group's accounting policies. The areas where significant judgments and estimates have been made in preparing the financial statements and their effect are disclosed within this note 1.

The consolidated financial statements have been prepared on a historical cost basis except for the valuation of hydrocarbon inventories.

Going concern

The financial statements of the Group are prepared on a going concern basis.

In undertaking a going concern review, the Directors have given careful consideration to the Group's financial projections prepared by management for the period to 31 March 2024 (the review period). The Directors have also considered significant known events beyond 31 March 2024. The projections reflect the Company's best estimate of expenditures and receipts for the period. The Directors have reviewed management's key assumptions on which these projections are based, including a downside price and other risking scenarios. The near-term cash forecasts are regularly updated and reviewed to enable continuous monitoring and management of the Group's cash flow and liquidity risk. The forecasts indicate that, including the expectation that the Company can amend capital commitments under some of its licences and taking into account other cost saving and capital management initiatives, the Group has sufficient capital resources for a period of 12 months from the date of approval of this annual report. The Group's debt matures in September 2024 and the forecasts currently show that the Group plans to refinance its debt.

As part of its analysis in making the going concern assumption, the Directors have considered the range of risks facing the business on an ongoing basis, as set out in the risk section of this Annual Report. The principal assumptions made in relation to the going concern assessment include the continued production from the Blythe H-1 well, the successful delivery of the Blythe H-2 well and subsequent gas production rates, the potential evolution of gas prices and potential future capital allocations on its operated assets in the UK Southern North Sea.

Following a disappointing result from the Southwark A2 well test and remediation programme, the Company, in conjunction with its joint venture partner CER, sanctioned the drilling of Blythe H-2, prioritising it ahead of Southwark A1 as a lower risk option. Gas rates from H2 are expected to initially be in the 30-40 mmscf/d range and the well is expected to be completed and producing within a period of three months from the spud date of 5th March.

The Company takes regular external advice on gas price forecasts. The base case uses the forward curve for near-term gas prices. The average gas price used in the review period is 130p/therm. Since the end of 2022 gas prices have fallen over 20%. This sustained fall in gas price during the review period would result in a covenant breach in the interest cover ratio. At the year end forward curve prices, no covenant breach was forecast. The Company's €100 million bond is subject to covenants that are measured biannually in June and December, being minimum liquidity of €5 million, net debt to EBITDA of a maximum of 2.5x and interest cover of a minimum of 5.0x, based on measures as defined in the facility agreement. The ratio of net debt to EBITDA at 31 December 2022 was 1.0 times and interest cover was 7.0 times. In the downside case, where gas prices are assumed to be 50% below the current forward curve, both the leverage ratio and interest cover ratio are forecast to be breached. In the event that a covenant is breached, an extension or waiver of this covenant would need to be negotiated with the Bond Trustee. The Directors, taking into account their assessment of Bondholders' interests and given the Group would pass the minimum liquidity test, believe this would be likely to be achieved, however it is not guaranteed.

The forecast also indicates in the base case the Group would need to minimise capital expenditures in the review period. This may include the requirement to agree revised work programmes or licence commitments with the UK authorities on licences where the Group has capital commitments as well as discretionary expenditures. If the Company is unsuccessful in agreeing revised terms this may result in the need to raise alternative funds on whatever terms are available at the time.

The Directors have concluded that the uncertainty around the volatility of the gas price and future production levels from the Blythe H-2 well, as well as the need to take other mitigating actions described above represent a material uncertainty which may cast significant doubt on the Group's ability to continue as a going concern.

As a result of their review, and despite the aforementioned material uncertainty, the Directors have confidence in the Group's forecasts and have a reasonable expectation that the Group will continue in operational existence for the going concern review period and have therefore used the going concern basis in preparing these consolidated financial statements.

Change in accounting policies

i) New accounting standards, interpretations and amendments effective from 1 January 2022

A number of new or amended standards became applicable for the current reporting period. The Group did not have to change its accounting policies or make retrospective adjustments as a result of adopting these standards.

- Onerous Contracts - Cost of Fulfilling a Contract (Amendments to IAS 37);
- Property, Plant and Equipment: Proceeds before Intended Use (Amendments to IAS 16);
- Annual Improvements to IFRS Standards 2018-2020 (Amendments to IFRS 1, IFRS 9, IFRS 16 and IAS 41); and
- References to Conceptual Framework (Amendments to IFRS 3).

ii) New standards, interpretations and amendments not yet effective

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

The following amendments are effective for the period beginning 1 January 2023:

- Disclosure of Accounting Policies (Amendments to IAS 1 and IFRS Practice Statement 2);
- Definition of Accounting Estimates (Amendments to IAS 8); and
- Deferred Tax Related to Assets and Liabilities arising from a Single Transaction (Amendments to IAS 12).

The following amendments are effective for the period beginning 1 January 2024:

- IFRS 16 Leases (Amendment - Liability in a Sale and Leaseback)
- IAS 1 Presentation of Financial Statements (Amendment - Classification of Liabilities as Current or Non-current)
- IAS 1 Presentation of Financial Statements (Amendment - Non-current Liabilities with Covenants)

The Group is currently assessing the impact of these new accounting standards and amendments. The Group does not believe that the amendments to IAS 1 will have a significant impact on the classification of its liabilities, as the conversion feature in its convertible debt instruments is classified as an equity instrument and therefore, does not affect the classification of its convertible debt as a non-current liability.

The Group does not expect any other standards issued by the IASB, but not yet effective, to have a material impact on the Group.

The principal accounting policies adopted are set out below.

Basis of consolidation

The Group Financial Statements consolidate the accounts of IOG plc and entities controlled by the Company (its subsidiary undertakings) drawn up to the statement of financial position date. Control is achieved where the investor is exposed or has rights to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. 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 elements of control. The results of subsidiaries acquired or sold are consolidated for the periods from or to the date on which control passed.

Where necessary, adjustments are made at the Group level to align the accounting policies of the subsidiaries to the Group's accounting policies.

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

Asset Acquisition

In the event of an asset acquisition, the cost of the acquisition is assigned to the individual assets and liabilities based on their relative fair values. All directly attributable costs are capitalised. Contingent consideration is accrued for when these amounts are considered probable and are discounted to present value based on the expected timing of payment.

Oil and gas exploration, development and producing assets

The Group adopts the following accounting policies for oil and gas asset expenditure, based on the stage of development of the assets:

1) Pre-Licence

Expenditure incurred prior to the acquisition and/or award of a licence interest is expensed to the Statement of Comprehensive Income as 'Exploration Expenses'.

2) Exploration and evaluation ('E&E')

Capitalisation

Costs incurred after rights to explore have been obtained, such as geological and geophysical surveys, drilling and commercial appraisal costs, and other directly attributable costs of exploration and evaluation including technical and overheads (including time writing as described under D&P capitalisation), are capitalised as intangible exploration and evaluation ('E&E') assets. The assessment of what constitutes an individual E&E asset is based on technical criteria but essentially either a single licence area or contiguous licence areas with consistent geological features are designated as individual E&E assets. Costs relating to the exploration and evaluation of gas interests are carried forward until the existence, or otherwise, of commercial reserves have been determined.

E&E costs are not amortised prior to the conclusion of appraisal activities. Once active exploration and evaluation is completed the asset is assessed for impairment. If commercial reserves are discovered then the carrying value of the E&E asset is reclassified as a development and production ('D&P') asset, within property, plant and equipment ('PPE'), following development sanction by the Board, but only after the carrying value is assessed for impairment at point of transfer and, where appropriate, its carrying value adjusted. Following development sanction by the Board, a Field Development Plan ('FDP') may be submitted. If it is subsequently assessed that commercial reserves have not been discovered, the E&E asset is written off to the Statement of Comprehensive Income. The Group's definition of commercial reserves for such purpose is proven and probable ('2P') reserves on an entitlement basis.

Intangible E&E assets that relate to E&E activities that are not yet determined to have resulted in the discovery of commercial reserves remain capitalised as intangible E&E assets at cost, subject to impairment assessments as set out below.

Impairment

Impairment

The Group's gas assets are analysed into cash generating units ('CGU') for impairment reporting purposes, with E&E asset impairment testing being performed at an individual asset level. E&E assets are reviewed for impairment when facts and circumstances arise that suggest that the carrying value of an E&E asset exceeds its recoverable amount. Such indicators would include but are not limited to: (i) adequate and sufficient data exists that render the resource uneconomic and unlikely to be developed; (ii) title to the asset is compromised; (iii) budgeted or planned expenditure is not expected in the foreseeable future; (iv) insufficient discovery of commercially viable resources leading to the discontinuation of activities; and (v) Rights to explore in an area have expired or will expire in the near future without renewal.

The recoverable amount of the individual asset is determined as the higher of its fair value less costs to sell and value in use. Impairment losses resulting from an impairment review are separately recognised and written off to the Statement of Comprehensive Income. Impaired assets are reviewed annually to determine whether any substantial change to their fair value amounts previously impaired would require reversal.

A previously recognised impairment loss is reversed if the recoverable amount increases because of a change in the estimates used to determine the recoverable amount, but not to an amount higher than the carrying amount that would have been determined had no impairment loss been recognised in prior periods. Recognition and reversal of impairments and impairment charges are credited/(charged) to a separate line item within the Statement of Comprehensive Income. Reversal of impairments and impairment charges are credited/(charged) to a separate line item within the Statement of Comprehensive Income.

3) Development and production ('D&P')

Capitalisation

Gas properties are stated at cost, less any accumulated depreciation and accumulated impairment losses. Expenditures associated with gas properties include the cost of facilities, pipelines, wells and sub-sea equipment together with E&E expenditures incurred in finding commercial reserves previously transferred from E&E assets as outlined in the policy above. An individual field development can form a single D&P asset but there may be cases, such as shared infrastructure, phased developments, or multiple fields around a single production facility when fields are grouped together to form a single D&P asset. The cost of development and production assets include the cost of acquisitions and purchases of such assets, directly attributable overheads, applicable borrowing costs for qualifying assets and the cost of recognising provisions for future consideration payments (see Note 17). The discounted cost for future decommissioning is also capitalised to the D&P asset. Rig day rate costs attributable to changes or adjustments to the drilling program due to rescheduling are considered as normal and inherent to the activity of drilling wells that form part of the infrastructure and therefore these costs are capitalised to the asset.

Depreciation and depletion

All costs relating to a development are accumulated and not depreciated/depleted until the commencement of production. Gas assets are depleted on a unit-of-production basis over the total proved and probable reserves of the field concerned, except in the case of assets whose useful life is shorter than the lifetime of the field, in which case the straight-line method is applied. This method takes into account expenditures incurred to date, together with estimated future capital expenditure expected to be incurred. Changes in the estimates of commercial reserves or future field development costs are accounted for prospectively. Significant items of shared gas infrastructure including facilities, platforms and pipelines will normally be depreciated on a straight-line basis over their expected useful life. The expected useful life of current gas infrastructure is 17 years, which corresponds to the assets design life.

Impairment

At each Statement of Financial Position date, the Group reviews the carrying amounts of its property, plant and equipment 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 recoverable amount is the higher of fair value less costs to sell and value-in-use. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are cash inflows that are largely independent of the cash inflows from other assets or group of assets; cash generating units (CGU). 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 cash generating unit for which the estimates of future cash flows have not been adjusted. The discount rate is derived from the Group's weighted average cost of capital and is adjusted where applicable to consider any specific risks relating to the country where the CGU is located. The discount rates applied in assessments of impairment are reassessed each year. The Company uses a risk adjusted discount rate of 9.38%, unless otherwise stated. The estimated future net cash flows represent the present value of the future cash flows expected to be derived from production of commercial reserves. If the recoverable amount of a cash generating unit is estimated to be less than the carrying amount, the carrying amount of the cash-generating unit is reduced to its recoverable amount. An impairment loss is recognised immediately in the Statement of Comprehensive Income. The CGU basis is generally the field, however, gas assets, including shared infrastructure assets may be accounted for on an aggregated basis where such assets are economically inter-dependent.

Pipeline fill

Natural gas which is used to fill pipelines and is necessary to bring a pipeline into working order is treated as a part of the cost of the related pipeline on the basis that it is not held for sale or consumed in a production process but is necessary for the operation of a facility during more than one operating cycle. Also, its cost cannot be recouped through sale (or is significantly impaired). This applies even if the part of inventory that is deemed to be an item of property, plant and equipment cannot be separated physically from the rest of inventory. It is valued at cost and is depreciated over the useful life of related asset.

4) Borrowing costs

Borrowing costs directly attributable to the construction of qualifying assets, which are assets that necessarily take a substantial period of time to prepare for their intended use, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use. All other borrowing costs are recognised as interest payable in the statement of comprehensive income in accordance with the effective interest method.

Assets other than oil and gas interests

Assets other than oil and gas interests are stated at cost, less accumulated depreciation and any provision for impairment. Depreciation is provided at rates estimated to write off the cost, less estimated residual value, of each asset over its expected useful life as follows: -

- Computer and office equipment: 33% straight line, with one full year's depreciation in year of acquisition; and
- Tenants improvements: 20% straight line, with one full year's depreciation in year of acquisition.
- Right of use assets: Straight line over the term of the lease

Provisions

Provisions are recognised when:

- the Group has a present legal or constructive obligation resulting from past events;
- it is more likely than not that an outflow of resources will be required to settle the obligation; and
- the amount can be reliably estimated.

Decommissioning

Provisions for decommissioning costs are recognised in accordance with IAS 37 Provisions, Contingent Liabilities and Contingent Assets. Provisions are recorded at the present value of the expenditures expected to be required to settle the Group's future obligations.

Provisions are reviewed at each reporting date to reflect the current best estimate of the cost at present value. Any change in the date on which provisions fall due will change the present value of the provision. These changes are treated as an administration expense. The unwinding of the discount is reflected as a finance expense.

In the case of a D&P and/or pipeline asset, since the future cost of decommissioning is regarded as part of the total investment to gain access to future economic benefits, this is included as part of the cost of the relevant D&P and/or pipeline asset.

Revenue

During the period, the Group recognised the commencement of revenues from the sale of gas and condensate and consequently adopted IFRS 15 Revenue from Contracts with Customers. The Group is principally engaged in the exploration, development and production of natural gas. The Group has concluded that it is the principal in its contract with customer arrangements, because it controls the goods before transferring them to the customer.

Revenue from contracts with customers is recognised when or as the Group satisfies a performance obligation by transferring control of a promised good or service to a customer. The transfer of control of natural gas and natural gas liquids coincides with title passing to the customer and the customer taking physical possession, generally on delivery of the natural gas or condensate to the agreed delivery point specified in the contract. In respect of gas sales, the delivery point is when the gas is delivered into the National Transmission System downstream of the Bacton gas terminal. Condensate is sold on an FCA basis when it is delivered onto the buyer's rail tank car loading manifold. The Group satisfies its performance obligations at a point in time.

When, or as, a performance obligation is satisfied, the Group recognises as revenue the amount of the transaction price that is allocated to that performance obligation. The Group's contracts with customers are deemed to contain one performance, the provision of natural gas or condensate. The transaction price is the amount of consideration to which the Group expects to be entitled. The transaction price is allocated to the performance obligations in the contract based on standalone selling prices of the goods promised. Contracts for the sale of natural gas and condensate are priced by reference to quoted prices. All revenue from these contracts is disclosed as revenue from contracts with customers.

Consideration payable to a customer for certain costs, claims, demands, liabilities and/or expenses suffered or incurred by the buyer under the sales contract are recognised as a reduction of the transaction price and, therefore, a incurred by the buyer under the sales contract are recognised as a reduction of the transaction price and, therefore, a reduction in revenue since the payment to the customer is not in exchange for distinct goods that the customers transfer to the Company. The credit terms range between 20-40 days after the month-end, depending on the customer.

Cost of sales

Production expenditure, gas properties depletion and movements in inventory, a result of under-lift of condensate production, are included in cost of sales. The Group recognises an under-lift asset as inventory for condensate production at the lower of cost and net realisable value, consistent with IAS 2, to represent a right to additional physical inventory. An under-lift of production from a field is included in current receivables.

Disposals

Net proceeds from any disposal of an E&E, D&P or pipeline asset are initially credited against the previously capitalised costs of that asset and any surplus or shortfall proceeds are credited or debited to the Statement of Comprehensive Income.

For the Farm down of an E&E, D&P or pipeline asset, proceeds from the farm-down are credited against the previously capitalised costs of the asset and any surplus or shortfall proceeds above or below the representative percentage of the carrying value of the asset or assets being farmed down are credited or debited to the Statement of Comprehensive Income accordingly.

Foreign currencies

The Group's presentational currency is GBP Sterling and has been selected based on the currency of the primary economic environment in which the Group operates. The Group's primary product is generally traded by reference to its pricing in GBP Sterling. The functional currency of all companies in the Group is also considered to be GBP Sterling. Transactions in currencies other than the functional currency of a company are recorded at a rate of exchange approximating to that prevailing at the date of the transaction. At each balance sheet date, monetary assets and liabilities that are denominated in currencies other than the functional currency are translated at the amounts prevailing at the balance sheet date and any gains or losses arising are recognised in the Consolidated Statement of Comprehensive Income.

Taxation

Current Tax

Tax is payable based upon taxable profit for the year. Taxable profit differs from net profit as reported in the Statement of Comprehensive Income because it excludes items of income or expense that are taxable or deductible on other years and it further excludes items that are never taxable or deductible. Any Group liability for current tax is calculated using tax rates that have been enacted or substantively enacted by the reporting date.

Deferred Tax

Deferred tax is the tax expected to be payable or recoverable on 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.

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

The carrying amount of deferred tax assets is reviewed at each reporting date 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 is realised. Deferred tax is charged or credited in the Statement of Comprehensive Income, except when it relates to items charged or credited directly to equity, in which case the deferred tax is also dealt with in equity. 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.

The amount of the asset or liability is determined using tax rates that have been enacted or substantively enacted by the reporting date and are expected to apply when the deferred tax liabilities/(assets) are settled/(recovered). Deferred tax balances are not discounted.

Investments & Loans (Company)

Non current investments in subsidiary undertakings are shown in the Company's Statement of Financial Position at

Non-current investments in subsidiary undertakings are shown in the Company's Statement of Financial Position at cost less any provision for permanent diminution of value.

Loans to subsidiary undertakings are stated at amortised cost and recognised in accordance with IFRS 9. The loans have no maturity date and are not repayable until the respective subsidiary entity has sufficient cash to repay the loan, however they are technically due on demand.

Leases

IFRS 16 sets out the principles for the recognition, measurement, presentation and disclosure of leases and requires lessees to account for all leases, with limited exceptions, under a single on-balance sheet model similar to the accounting for finance leases under IAS 17. Under IFRS 16, at the commencement date of a lease, a lessee is required to recognise a liability to make lease payments ('lease liability') and an asset representing the right to use the underlying asset during the lease term ('right-of-use asset', 'ROU'). Lease liabilities are measured at the present value of future lease payments over the reasonably certain lease term. Variable lease payments that do not depend on an index or a rate are not included in the lease liability. Such payments are expensed as incurred throughout the lease term.

Lessees are required to separately recognise the interest expense associated with the unwinding of the lease liability and the depreciation expense on the right-of-use asset. As the leases relate to D&P work scopes the depreciation expense is capitalised and treated as the cost of the underlying D&P asset. These costs replace amounts previously recognised as operating expenditure in respect of operating leases in accordance with IAS 17. After completion of Development phase, once the assets come into operation the depreciation of the right of use asset will be charged to the income statement on straight line basis over the course of the lease term.

The Group adopted IFRS 16 on 1 January 2019 using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information, instead recognising the cumulative effect as an adjustment to opening retained earnings and the Group applied the standard prospectively.

The Group has elected to apply the following optional practical expedients under the standard:

- Short-term leases - those with terms of 12 months or less at date of adoption
- Low-value leases - those with a value less than £5,000

During 2022, the ROU assets and lease obligations classified in accordance with IFRS 16, relate to office leases, the Saturn Banks Pipeline permission to cross the foreshore, the Noble Hans Deul drilling rig contract, Charter of PSV "VOS Paradise" and Charter of ERRV "Esvagt Champion". The incremental borrowing rate of 10.9% (2021: 9.3%) was applied to the drilling rig and support vessel ROU assets, and 9.3% (2021: 9.3%) for the office leases, in arriving at net present value of future lease payments, recognising they belong to similar asset classes with similar lease terms. The internal borrowing rate for Saturn Banks Pipeline was retained at 11.5% as it belongs to a different asset class and has longer lease term. The ROU for Noble Hans Deul was increased in line with the extension option.

The Group has elected to utilise the practical expedient when accounting for the Noble Rig, PSV and ERVV contract to not separate non-lease components from lease components, and instead account for each lease component and any non-lease component as a single component. The leases are for the benefit of the joint operation operated by the Group. For leases related to joint operations where the Group is the only party with the legal obligation to make lease payments to the lessor, the full lease liability and ROU asset will be recognised on the Group Statement of Financial Position. This is the case for the drilling rig contract and associated support vessels described above, as the Group, as operator of the joint operation, is the sole signatory to the lease. As the underlying asset is used for the performance of the joint operation agreement, the Group will recharge the associated costs in line with the joint operating agreement.

The Company depreciates the ROU assets on a straight-line basis over the length of the lease unless management determines this is not representative of the useful life, in which case, management will estimate the useful life of the asset to be used.

The liability is remeasured when there is a change in future lease payments arising from a change in an index or rate or if the Group changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liability is remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use asset or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

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

Financial Instruments

Financial instruments are recognised when the Group becomes a party to the contractual provisions of the instrument and are subsequently measured at amortised cost.

Classification and measurement of financial assets

The initial classification of a financial asset depends upon the Group's business model for managing its financial assets and the contractual terms of the cash flows. The Group's financial assets are measured at amortised cost and are held within a business model whose objective is to hold assets to collect contractual cash flows and its contractual terms give rise on specified dates to cash flows that represent solely payments of principal and interest.

The Group's cash and cash equivalents and other receivables are measured at amortised cost. Other receivables are initially measured at fair value. The Group holds other receivables with the objective to collect the contractual cash flows and therefore measures them subsequently at amortised cost.

The Group has financial assets measured at FVOCI (Fair Value Through Other Comprehensive Income) or FVTPL (Fair Value Through the Statement of Profit or Loss).

Fair value measurement

A number of assets and liabilities included in the Group's financial statements require measurement at, and/or disclosure of, fair value.

The fair value measurement of the Group's financial and non-financial assets and liabilities utilises market observable inputs and data as far as possible. Inputs used in determining fair value measurements are categorised into different levels based on how observable the inputs used in the valuation technique utilised are (the 'fair value hierarchy'):

- Level 1: Quoted prices in active markets for identical items (unadjusted)

- Level 2: Observable direct or indirect inputs other than Level 1 inputs

- Level 3: Unobservable inputs (i.e. not derived from market data).

The classification of an item into the above levels is based on the lowest level of the inputs used that has a significant effect on the fair value measurement of the item. Transfers of items between levels are recognised in the period they occur.

Investment in and disposal of Norwegian bond

The company carried an investment in its Norwegian bond until September 2021. These bonds were denominated in Euro's and were adjusted to mark-to-market and revalued at period end rates. These holdings were sold in the open market at spot price and a profit / loss on sale was recognised in the statement of comprehensive income on disposal.

Restricted cash

Restricted cash includes cash balances that are subject to access restrictions or have conditions attached to their drawdown. Included in this are monies raised from its Norwegian bond placing held in Debt Servicing Retention account and subject to defined conditions. Also included are balances held as collateralised security in the Group's name for future expenditures such as Decommissioning.

Cash and cash equivalents

Cash includes cash on hand and demand deposits with any bank or other financial institution. Cash equivalents are short-term, highly liquid investments that are readily convertible to known amounts of cash which are subject to an insignificant risk of changes in value.

Impairment of financial assets

The Group recognises loss allowances for expected credit losses ('ECL's) on its financial assets measured at amortised cost. Due to the nature of its financial assets, the Group measures loss allowances at an amount equal to the lifetime ECLs. Lifetime ECLs are the anticipated ECLs that result from all possible default events over the expected life of a financial asset. ECLs are a probability-weighted estimate of credit losses. The Company has carried out an analysis of the balances outstanding at the end of the period and assessed the likelihood of repayment from its subsidiaries. It believes that there is no significant increase in credit risk from the prior year and, if anything, the position is strengthened with the sanction of the phase 1 project resulting in future cashflows for its subsidiaries.

Classification and measurement of financial liabilities

A financial liability is initially classified as measured at amortised cost or FVTPL. A financial liability is classified as measured at FVTPL if it is held-for-trading, a derivative or designated as FVTPL on initial recognition.

The Group's accounts payable, accrued liabilities, operators balances and long-term debt are measured at amortised cost.

Accounts payable, accrued liabilities and operators balances are initially measured at fair value and subsequently measured at amortised cost. Accounts payable and accrued liabilities are presented as current liabilities unless payment is not due within 12 months after the reporting period.

Long-term debt is initially measured at fair value, net of transaction costs incurred. The contractual cash flows of the long-term debt are made up of solely principal and interest, therefore long-term debt is subsequently measured at amortised cost. Long-term debt is classified as current when payment is due within 12 months after the reporting period.

Where warrants are issued in lieu of arrangement fees on debt facilities, the fair value of the warrants are measured at the date of grant as determined through the use of the Black Scholes technique. The fair value determined at the grant date of the warrants is recognised in the Group's warrant reserve and is amortised as a finance cost over the life of the facility.

The outstanding LOG loans are unsecured against any assets or Company of the Group.

Convertible loan notes

Upon issue, convertible notes are assessed as to whether it is necessary to separate the loan into an equity and liability component at the date of issue. If the bifurcation is considered material the liability component is recognised initially at its fair value. Subsequent to initial recognition, it is carried at amortised carrying value using the effective interest method until the liability is extinguished on conversion or redemption of the notes. The equity component is the residual amount of the convertible note after deducting the fair value of the liability component. This is recognised and included in equity and is not subsequently re-measured.

Contingent consideration payable

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 the fair values are adjusted against the cost of acquisition where they qualify as measurement period adjustments (see below). All other subsequent changes in the fair value of contingent considerations classified either as an asset or liability are accounted for in accordance with relevant IFRSs with any gains or losses recorded in the income statement unless it is classified as equity.

Equity

Equity instruments issued by the Company are recorded at the proceeds received, net of direct issue costs, allocated between share capital and share premium. The costs of issuing new share capital are written off against the share premium account arising out of the proceeds of the new issue.

Share-based payments

The Company have applied the requirements of IFRS 2 Share-based payments. The Company issues equity share options, to certain employees and contractors, as direct compensation for both salary and fees sacrificed in lieu of such share options. Other Long-Term Incentive Plan ('LTIP') and Company Share Ownership Plan ('CSOP') share options may be awarded to incentivise and reward successful corporate and individual performance. The fair value of these awards has been determined at the date of the grant of the award allowing for the effect of any market-based performance conditions.

The fair value of share options awarded, in lieu of salary sacrifice, is expensed on the effective date of grant, with no vesting conditions applied. The fair value is deemed to be the actual salary sacrificed.

For LTIP and CSOP share option awards, based upon incentive and performance, the fair value, adjusted by the estimate of the number of awards that will eventually vest because of non-market conditions, is expensed uniformly over the vesting period and is charged to the Statement of Comprehensive Income, together with an increase in equity reserves, over a similar period. The fair values are calculated using an option pricing model with suitable modifications to allow for early exercise. The inputs to the model include: the share price at the date of grant; exercise price; expected volatility; expected dividends; risk-free rate of interest; and patterns of exercise of the plan participants. Where the terms and conditions of options are modified before they vest, the increase in the fair value of the options, measured immediately before and after the modification, is also charged to the Statement of Comprehensive Income over the remaining vesting period. Share options issued by the Company that are subject to market-based vesting conditions, as defined in IFRS 2, are ignored for the purposes of estimating the number of equity shares that will vest; these conditions have already been taken into account when fair valuing the share options.

Non-market vesting conditions are not taken into account when estimating the fair value of share options at the grant date; such conditions are taken into account through adjusting the number of equity instruments included in the measurement of the amount charged to the Statement of Comprehensive Income over the vesting period so that, ultimately, the amount recognised equates to the number of equity instruments that actually vest. The expense in the Statement of Comprehensive Income in relation to share options represents the product of the total number of options anticipated to vest and the fair value of these options at the date of grant.

Share options where the performance conditions are service-related and non-market in nature, the cumulative charge to the income statement is reversed only where an employee in receipt of share options leaves the Group prior to completion of the service period and forfeits the options granted and/or performance conditions are not expected to be satisfied. Where an equity settled award is cancelled, it is treated as if it had vested on the date of cancellation, and satisfied. Where an equity-settled award is cancelled, it is treated as if it had vested on the date of cancellation, and any expense not yet recognised for the award is recognised immediately.

The proceeds received by the Company on the exercise of share entitlements are credited to share capital and share premium. When share options which have not been exercised reach the end of the original contractual life, the value of the share options is transferred from the share option reserve to retained earnings.

The fair value of warrants issued to third parties is calculated by reference to the service provided, or if this is not considered possible, calculated in the same way as for LTIP share options as detailed above. Typically, these amounts are related to debt issues and are included in the effective interest rate calculation of borrowings.

Earnings or Loss per share

Earnings or Loss per share is calculated as profit/loss attributable to shareholders divided by the weighted average number of ordinary shares in issue for the relevant period. Diluted earnings per share is calculated using the weighted average number of ordinary shares in issue plus the weighted average number of ordinary shares that would be in issue on the conversion of all relevant potentially dilutive shares to ordinary shares adjusted for any proceeds obtained on the exercise of any options and warrants. Where the impact of converted shares would be anti-dilutive, they are excluded from the calculation.

Critical accounting judgements and key sources of estimation uncertainty

The preparation of financial statements in conformity with IFRS requires management to make judgements, estimates and assumptions that affect the application of policies and reported amounts of assets and liabilities, income and expenses. The estimates and associated assumptions are based on historical experience and factors that are believed to be reasonable under the circumstances, the results of which form the basis of making judgements about carrying values of assets and liabilities that are not clear from other sources. Actual results may differ from these estimates.

The following are the critical judgements that management has made in the process of applying the entity's accounting policies and that have the most significant effect on the amounts recognised in financial statements.

Critical accounting judgements

Where judgements have been applied, these can affect the outcome and results within the Financial Statements.

<u>Determination of cash-generating units ("CGUs") (note 10 & 11)</u>

The determination of the appropriate grouping of assets into a CGU for impairment purposes require significant management judgement when defining an asset, or group of assets that generate cash inflows that are largely independent of the cash inflows from other assets or groups of assets. For example, individual gas properties may form separate CGUs whilst certain 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. CGUs are determined by consideration to similar geological structure, shared infrastructure, geographical proximity, commodity type, similar exposure to market risks and materiality. The Group's cash generating units are normally, but not always, single development or production areas. With respect to the Group's Southern North Sea gas production and development assets, the CGU is considered by field or Groups of proximate fields which supports the value of shared infrastructure assets. In the prior year, the D&P Phase 1 assets were treated as one CGU, however, following production from the Blythe and Elgood CGU, and the results on the Southwark CGU during the year, these fields are now considered to generate independent cashflows that support the share gas infrastructure network. E&E assets are considered to form a single CGU on a "hub" basis that corresponds to geographical proximity for the purposes of an impairment assessment under IFRS 6.

<u>Carrying value of intangible exploration and evaluation assets (note 10)</u>

The amounts for intangible exploration and evaluation assets represent active evaluation projects. These amounts will be written off to the income statement as exploration costs unless commercial reserves are established, or the determination process is not completed and there are no indications of impairment in accordance with the Group's accounting policy. The process of determining whether there is an indicator for impairment or impairment reversal and the subsequent calculation requires critical judgement. The key areas in which management has applied judgement are as follows: the Group's intention to proceed with a future work programme for a licence; the likelihood of licence renewal or extension; the review of new legislation or regulations that may impact the economic terms of the Group's licence interests: the assessment of whether sufficient data exists to indicate that, although a development in the specific area is likely to proceed, the carrying amount of the exploration and evaluation asset is unlikely to be recovered in full from successful development or by sale and the success of a well result or geological or geophysical survey.

<u>Impairment of property plant and equipment assets (note 11)</u>

Management is required to assess its gas assets for indicators of impairment. D&P assets are reviewed for impairment by reference to indicators set out in IAS 36, which is inherently judgemental. Indicators of D&P assets include, but are not limited to:

- Significant downward trend changes long term gas price
- Any information available that would lead to a reduction in the reservoir estimates, either performance or via an updated reserves assessment by a competent person
- Significant cost overruns that would impact the economics of the CGU / asset
- Any commercial changes that would impact the economics of the CGU / asset
- Any regulatory, governance or environmental changes that would impact the asset's ability to function as previously envisaged.

During the year, the Elgood and Southwark reserves were downgraded following the results of production from the Elgood field and the Southwark A-2 well which the Group determined was an indicator of impairment (see note 11). The results of future developments of the Group's assets may be different to current management expectations and may result in further impairment or an impairment reversal dependent on the outcome of those developments, which would have an impact on the Group's financial statements. The carrying value of D&P gas assets is disclosed in note 11. The carrying value of related investments in the Company Statement of Financial Position is disclosed above.

Recognition of finance leases (note 23)

An area that carries significant judgement is around the accounting for the finance lease assumptions for the Shelf Perseverance rig contract, charter of support vessels, the PSV supply vessel & charter of ERRV (emergency rapid response vessel). These contracts have been assessed to fall within the scope of IFRS 16 and judgements around the initial contract length, subsequent extension (in case of rig contract) and the incremental borrowing rate have been made by Management.

Critical accounting judgements and key sources of estimation uncertainty (continued)

Critical accounting judgements (continued)

Going concern

Refer to above.

Key sources of estimation uncertainty

The key assumptions concerning the future and other key sources of estimation uncertainty at the balance sheet date 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.

Decommissioning estimates (note 17)

Provisions for decommissioning obligations are made on the best estimate of the likely committed cash outflow. The Company engages specialist input from third party consultancy experts to estimate the cost to perform the necessary remediation work at the reporting date. The third-party expert has experience in the industry and location where the Group operates and has assisted the Group's operations in the past. This enables a degree of knowledge of conditions specifically relevant to the Group. The third-party conducted a detailed review, provided a range of cost estimates for decommissioning of wells and infrastructure and site remediation. Management review and challenge the method and cost ranges where appropriate, using its own external sources through current contractors and market. The third-party expert estimates are on an undiscounted basis. Provision for environmental clean-up and remediation costs is based on current legal and contractual requirements, technology and management's estimate of costs with reference to current price levels.

Changes to the type of remediation method, legislation, including in relation to climate change, well condition, technology and equipment available in the Group's country of operation can all have a significant impact on the cost estimate that may result in the cost being higher than the current upper-range of the estimate provided.

The estimation of the timing of well abandonment, inflation and discount rates is also considered to be judgemental and can have a significant impact on the net present value of the obligation. Abandonment timing is forecast to occur at the expiration, or if planned renewal, expected expiration of the licence term. In respect of inflation, management references UK long-term inflation targets published by the OBR, and the risk-free discount rate estimate references the UK and Europe central banks when making such estimates (see note 22).

Impairment of property plant and equipment - development & production assets (note 11)

At each Statement of Financial Position date, the Group reviews the carrying amounts of its CGUs to determine whether there is any indication that those assets have suffered an impairment. The Group generally assesses the recoverable amount of a CGU through the value-in-use method, using the estimated future cash flows which 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 or CGU. The following are key estimates used in that assessment when calculating development & production assets recoverable amount:

Commercial Reserves

Commercial reserves are proven and probable ('2P') oil and gas reserves, calculated on an entitlement basis. Estimates of commercial reserves underpin the calculation of depletion and amortisation on a UOP basis, gas asset impairments, as well as the value-in-use calculation. Estimates of commercial reserves include estimates of the amount of gas in place, assumptions about reservoir performance over the life of the field and assumptions about commercial factors which, in turn, will be affected by the future gas price. The Group prepares Proved and Probable reserves estimates in accordance with the reserve definitions guidelines defined in SPE Petroleum Resources Management System 2018 (PRMS 2018). Reserves estimates are reported annually by the Board. The self-certified estimated future production profiles are used in the life of the fields which in turn are used as a basis in the value-in-use calculation.

Commodity prices

A seasonally adjusted long-term assumption for natural UK NBP gas prices are used for future cash flows in accordance with the Group's corporate assumptions. Field specific premiums and discounts are used where applicable.

Capital expenditure

Field development is capital intensive and future capital expenditure has a significant bearing on the value of a gas development asset. In addition, capital expenditure may be required for producing fields to increase production and/or extend the life of the field. Cost assumptions are based on operator and/or service contractor cost estimates or specific contracts where available.

Critical accounting judgements and key sources of estimation uncertainty (continued)

Key sources of estimation uncertainty (continued)

Impairment of property plant and equipment - development & production assets (note 11)

Discount rates

Discount rates reflect the current market assessment of the risks specific to the upstream gas sector and are based on the weighted average cost of capital for the Group. Where appropriate, the rates are adjusted to reflect the market assessment of any risk specific to the field for which future estimated cash flows have not been adjusted. The Group has applied a risk adjusted discount rate of 9.38% for the current year (2021: 9.25%). A one per cent increase in the discount rate does not result in an additional impairment.

Sensitivity to changes in assumptions

A potential change in any of the above assumptions may cause the estimated recoverable value to be lower than the carrying value, resulting in an impairment loss. The assumptions which would have the greatest impact on the recoverable amounts of the fields are commercial reserves volumes (linked to recoverable reserves) and commodity prices. In respect of the D&P Phase 1 assets, sensitivity analysis indicates that if gas prices were to fall by 10% below forecast there an additional post-tax impairment of £24.4 million would have occurred, and an increase of 10% would result in an £18.6 million increase in recoverable amount.

Investments in subsidiaries

If circumstances indicate that impairment may exist, investments in and the value of any loans to subsidiary undertakings of the Company are evaluated using market values, where available, or the discounted expected future cash flows of the investment. If these cash flows are lower than the Company's carrying value of the investment or loan amount due, an impairment charge is recorded in the Company. Evaluation of impairments on such investments involves significant management judgement and may differ from actual results.

Finance leases

− The determination of lease term for some lease contracts in which the Group is a lessee, including whether the Company is reasonably certain to exercise lessee options (see note 23).

− The determination of the incremental borrowing rate used to measure lease liabilities (see note 1).

Fair value of share options and warrants

The fair value of options and warrants is calculated using appropriate estimates of expected volatility, risk free rates of return, expected life of the options/warrants, the dividend growth rate, the number of options expected to vest and the impact of any attached conditions of exercise. See above for further details of these assumptions.

Prior period adjustment

An error was identified in the accounting for prior period prior period personnel costs recognised in 2021 financial statements. An over accrual of personnel costs of £1.9 million was recognised in previously reported 2021 administration expenses of £4.0 million, which formed part of operating loss of £1.5 million, and total comprehensive loss for the year of £4.3 million. Due to performance measures not being met during 2021, total personnel costs incurred in the period was £1.4 million lower. As these personnel costs predominantly related to the development of the Group's E&E and D&P assets, the costs were subsequently charged to Intangible and PPE assets and adjusted through the restated prior year accounts, as presented in the table below.

The restated 2021 personnel costs has an impact on all primary statements and certain notes to the accounts on both a consolidated and Company basis.

The 2021 comparatives have been restated in these financial statements to include the effect of the adjustments noted above. A third consolidated statement of financial position as at 1 January 2021 is not required under paragraph 10(f) of IAS 1 Presentation of financial statements, as the restatement has had no effect on the statement of financial position as at that date.

The adjustment has been corrected as at 31 December 2021 as per tables below:

	31 December 2021	Adjustment	Restated 31 December 2021
Consolidated Statement of Financial Position	**£000**	**£000**	**£000**
Intangible assets	950	44	994
Property, plant, and equipment: D&P assets	138,403	402	138,805
- Trade and other payables	(44,880)	1,412	(43,468)
Accumulated losses	42,263	(1,858)	40,405
Consolidated Statement of Comprehensive Income			
Administrative expenses	(3,960)	1,858	(2,102)
Total comprehensive loss for the year	(4,266)	1,858	(2,408)
Operating (loss)/ profit	(1,489)	1,858	369
Consolidated Cash Flow Statement			
Loss for the year	(4,266)	1,858	(2,408)
Movement in trade and other payables	25,499	(1,858)	23,641

	31 December 2021	Adjustment	Restated 31 December 2021
Company Statement of Financial Position	**£000**	**£000**	**£000**
- Amounts due from subsidiaries	109,195	446	109,641
- Trade and other payables	(22,513)	1,412	(21,101)
Accumulated losses	20,094	(1,858)	18,236
Company Cash Flow Statement			
Loss for the year	(3,643)	1,858	(1,785)
Movement in trade and other payables	25,499	(1,858)	23,641

2 Segmental information

The Group complies with IFRS 8, Operating Segments, which requires operating segments to be identified based upon internal reports about components of the Group that are regularly reviewed by the Directors to allocate resources to the segments and to assess their performance. In the opinion of the Directors, the operations of the Group comprise one class of business, being the development, production and exploration of oil and gas opportunities in the UK Southern North Sea.

3 Revenue

The Group's total revenue is stated from its contracts with customers relating to the following sales:

	2022	2021
	£000	£000
Gas sales	**71,840**	-
Condensate sales	**3,566**	-
Total Revenue	**75,406**	-

Included in revenues arising from gas sales are revenues of £71.8 million (2021: £nil) which arose from sales to BP Gas Marketing Limited, the Group's largest customer. No other single customers contributed 10 per cent or more to the Group's revenue in either 2022 or 2021.

4 Cost of sales

	2022	2021

	£000	£000
Operating Costs	**(10,078)**	-
Increase in Inventory	**40**	-
Depletion	**(13,188)**	-
Other Operating Expenditure	**(415)**	-
	(23,641)	-

Cost of sales for 2022 is £23.6 million (2021: £nil), representing operating costs of £10.1 million (2021: £nil), an increase in condensate inventory of £40,000 (2021: £nil), depletion of £13.2 million (2021: £nil) and other operating expenditure of £0.4 million (2021: £nil).

5 Operating loss

The Group's operating loss (2021: loss) is stated after charging / (crediting) the following:

	2022 £000	2021 £000
Fees payable to the Company's auditor:		
- for the audit of the Group's financial statements	**150**	128
Non-audit services	**41**	7
Of which		
for the audit of the Company's financial statements	**77**	62
Depreciation, depletion and amortisation	**13,686**	519
Project, pre-licence and exploration expenses	**182**	104
Impairment of oil and gas properties	**51,007**	865
Effect of exchange rate changes on Bond	**4,620**	(5,901)
Effects of exchange rate changes on cash and cash equivalents	**465**	2,461
Effects of exchange rate changes on Leases	**(341)**	-

Foreign exchange loss of £4.7 million (2021: gain of £3.4 million) relates mostly to EUR strengthening affecting the €100 million Norwegian Bonds.

6 Personnel costs

During the year, the average number of personnel, including contract personnel, for both the Company and Group was:

	2022 Number	2021 Number
Management / technical / operations	**51**	52
of which: Directors	**5**	5
Personnel costs Group and Company	**£000**	£000
Wages, salaries, fees and other direct costs	**6,904**	4,655
Social security costs	**1,028**	613
Pension costs	**343**	298
Share-based payments	**844**	1,284
	9,119	6,850

Note that project contract personnel, capitalised directly to project cost centres, are excluded from the above personnel cost figures.

Of the total personnel costs of £9.1 million (2021: £6.8 million) plus the other admin pool costs of £2.5 million (2021: £2.3 million), £6.0 million was capitalised to the balance sheet under PP&E (2021: £6.3 millions), £972,000 to Intangibles (2021: £655,000), and £2.2 million expensed to operating costs (2021: £nil).

Key management personnel are deemed to be the Directors, the Chief Financial Officer, the General Counsel & Company Secretary and the Head of Capital Markets & ESG.

Total key management personnel remuneration is:

	2022	2021
Group and Company	**£000**	£000

Group and Company	£000	£000
Wages, salaries, fees and other direct costs	**1,442**	1,646
Social security costs	**347**	237
Pension costs and other benefits	**343**	148
Share-based payments	**505**	776
	2,637	2,807

Directors' emoluments (which are included in administration expenses) and interests are shown in the Directors' Remuneration Report on pages 26 to 27. Short term benefits are deemed to be salary/fees, salary/fees sacrificed, bonus and benefits. No post-employment, long term or termination payments were made during the year.

The salary amounts are those cash amounts paid to Directors and key management personnel during the year. Social security costs for the year for key management personnel were £347,000 (2021: £237,000). Amounts of salary and/or fees outstanding at 31 December 2022 to which these terms relate totalled £nil (31 December 2021: £nil) for Directors and key management personnel and £nil (2021: £nil) for other personnel.

The share-based payment amounts represent the charges for share options during the year. For the current Directors at 31 December 2022, the service agreements provide that the full contractual amount will be paid in cash.

Personnel costs in 2021 have been restated; see note 1 for details.

7 Finance expense

	2022 **£000**	2021 £000
Interest on loans	**206**	-
Other finance charges	**23**	-
Current year loan finance charges	**560**	560
Unwinding of discount on decommissioning provision	**449**	(14)
Unwinding of discount on convertible loan	**1,000**	1,001
Unwinding of deferred consideration provisions	**91**	(118)
Unwinding of discount on lease liability	**1,882**	1,637
Interest on bonds	**8,756**	8,253
Capitalisation of interest on bonds[1]	**(1,853)**	(8,253)
	11,114	3,066

[1] During the Phase 1 development, 1st quarter 2022 interest paid in the Norwegian bonds was capitalised to the Phase 1 assets proportionately based on capital expenditure during the quarter. The capitalisation of the bond interest has cessed on the commencement of Blythe and Elgood production in 2022.

As at 31 December 2022, there were no interest-bearing loans outstanding other than the Norwegian Bonds (see note 22). During the year, the interest associated with the Bond was capitalised to D&P project costs as the bond drawdowns are purposefully used to finance the development of the project assets, until the assets became substantially available for their intended use. Interest on the Bond is no longer capitalised to D&P project costs but expensed to the Statement of Comprehensive Income as incurred.

8 Taxation

a) Current taxation

There was no tax charge during the year as the Group loss was not chargeable to corporation tax. Applicable expenditures to date will be accumulated for offset against future tax charges. The reasons for the difference between the actual tax charge for the year and the standard rate of corporation tax in the United Kingdom applied to profits for the year are as follows:

	2022 **£000**	2021 £000
(Loss)/profit before income taxes	**(17,087)**	(2,408)
Expected tax expense/(credit) based on the standard rate of United Kingdom corporation tax at the domestic rate of 40%[1] (2021: 40%)	**(6,834)**	(1,706)
Difference in tax rates	**3,476**	1,168
Expenses not deductible for tax purposes	**1,289**	(77)
Excess allowances	**(17,117)**	-
Deferred Energy Profits Levy	**11,362**	-
Income not taxable	**-**	(7,618)
Group relief claimed		(2)

Group relief claimed	**-**	(2)
Unrecognised taxable losses carried forward	**19,186**	8,235
Total tax expense	**11,362**	-

1 The standard rate of corporation tax of 40% (2021: 40%), including the supplemental corporation tax charge of 10% (2021:10%) is levied in respect of UK ring fence profit. Non-ring fenced profits are taxed at the standard rate of corporation tax of 19% (changing to 25% from 1 April 2023). Given that the Group's activities are primarily focused on activities which will generate income within the UK ring fence the 40% has been regarded as the appropriate rate for the reconciliation above. On 26 May 2022 the government announced a new Energy Profits Levy (EPL), 25% surcharge, will apply to ring fence oil and gas profits generated from that day until 31 December 2025. It was then announced that the EPL the rate will increase to 35% for ring fence oil and gas profits generated from 1 January 2023 to 31 March 2028. These laws have now been enacted by balance sheet date.

b) Deferred taxation

Due to the nature of the Group's exploration and appraisal activities there is a long lead time in either developing or otherwise realising exploration assets. The amount of deductible temporary differences, unused tax losses and unused tax credits for which no deferred tax asset is recognised in the statement of financial position is £258.6 million (2021: £220.6 million). There are also accelerated capital allowances of £116.4 million (2021: £111.0 million).

The Group has not recognised a deferred tax asset at 31 December 2022 (2021: £nil) on the basis that the Group would expect the point of recognition to be when the Group has some level of certainty of production showing that the Group is making profits in line with the underlying economic model which would support the recognition. A deferred tax asset has only been recognised on deductible temporary differences up to the amount of taxable temporary differences.

Energy Profit Levy

The Energy (Oil and Gas) Profits Levy was announced on 26 May 2022 and legislated for in July 2022. This was a new, temporary 35% levy on ring fence profits of oil and gas companies. This was in addition to Ring Fence Corporation Tax which is charged at 30% and the Supplementary Charge which is charged at 10%. The levy included a new 80% investment allowance and was due to expire by 31 December 2025. This measure increases the rate of the levy to 35% and extends the time that the levy applies to 31 March 2028. In respect of Energy Profits Levy (EPL) a net deferred tax liability of £11.4 million has been recognised.

The Group has carried forward ring fence tax losses of £239.3m (2021: £196.4 million), EPL losses of £21.0 million (2021: £nil) and non-ring fence tax losses of £24.2 million (2021: £16.6 million).

Deferred tax	**2022 £000**	2021 £000
Net book value in excess of capital allowances	79,852	55,718
Decommissioning provision	(8,869)	-
Investment allowance	(394)	-
Tax losses	(59,227)	(55,718)
Net deferred tax loss	11,362	-

9 Loss per share

		2022 £000	2021 £000
Loss for the year attributable to shareholders (Numerator)		**(28,449)**	(2,408)
Weighted average number of Ordinary Shares: basic (Denominator)		**525,037,353**	513,584,870
Add potentially dilutive shares:	Convertible loan notes	**60,872,631**	60,872,631
	Salary/Fee sacrifice options	**3,198,288**	4,325,027
	LTIP/CSOP	**30,206,628**	26,369,136
	Warrants	**20,000,000**	20,000,000
Diluted		**639,314,900**	625,151,664
Loss per share in pence:	basic	**(5.4p)**	(0.4p)

Diluted earnings per share is calculated based upon the weighted average number of Ordinary Shares plus the weighted average number of Ordinary Shares that would be issued upon conversion of potentially dilutive share options, convertible loan notes and warrants into Ordinary Shares.

There is no difference between the basic loss per Ordinary Share and the diluted loss per Ordinary Share for the years ended 31 December 2022 and 2021 as all potential Ordinary Shares outstanding are anti-dilutive. In 2022, there were no anti-dilutive instruments that were not included in the calculations that would have had a material impact on the basic earnings per share.

There are no significant Ordinary Share issues post the reporting date, save for those disclosed in note 28 that would materially affect this calculation.

10 Intangible assets

Group

	Exploration & evaluation assets 2022	**Company & IT software assets 2022**	**Total 2022**	Exploration & evaluation assets (Restated) 2021	Company & IT software assets 2021	Total (Restated) 2021
	£000	**£000**	**£000**	£000	£000	£000
At cost						
At beginning of the year (restated)[1]	**994**	**336**	**1,330**	13,875	321	14,196
Additions	**2,167**	**5**	**2,172**	549	15	564
Disposals	**-**	**(29)**	**(29)**	-	-	-
Disposals prior periods[2]		**-**		(13,430)	-	(13,430)
At end of the year	**3,161**	**312**	**3,473**	994	336	1,330
Amortisation						
At beginning of the year (restated)[1]	**-**	**(261)**	**(261)**	(12,565)	(151)	(12,716)
Amortisation	**-**	**(43)**	**(43)**	-	(110)	(110)
Impairment	**-**	**-**	**-**	(865)	-	(865)
Disposals prior periods[2]	**-**	**-**	**-**	13,430	-	13,430
At end of the year	**-**	**(304)**	**(304)**	-	(261)	(261)
Net book value						
At 31 December 2022	**3,161**	**8**	**3,169**			
At 1 January 2022	994	75	1,069			
At 1 January 2021	1,309	170	1,479			

[1] *Skipper licence was relinquished and impaired in 2019 Both Skipper related costs and accumulated impairments of £22.3M have been derecognised from the 2021 opening balance. There is £nil impact on Group Statement of Financial Position in 2022.*

[2] *After completing the technical analysis of Harvey, the Group fully determined the Harvey licence in December 2021. Harvey licence cost of £13.4 million were fully impaired in 2021. Both the costs and accumulated impairments of the Harvey licence of £13.4 million have been derecognised in the comparative period in the above table. There is £nil impact on Group Statement of Financial Position in 2022.*

The Group does not hold any property, plant and equipment within exploration and evaluation assets.

The additions to E&E assets during the year relate predominantly to geological and geophysical surveys, well planning and contracting activities in respect to the Goddard and Kelham North/Central appraisal wells.

The amount for Exploration and evaluation assets represents active exploration and appraisal projects. These will ultimately be written off to the Income Statement as exploration costs if commercial reserves are not established but are carried forward in the Statement of Financial Position whilst the determination process is not yet completed and there are no indications of impairment having regard to the indicators under IFRS 6.

In accordance with its accounting policies each CGU is evaluated annually for impairment, with an impairment test required when a change in facts and circumstances, in particular with regard to the remaining licence terms, likelihood of renewal, likelihood of further expenditures and ongoing acquired data for each area, result in an indication of impairment. Exploration and evaluation assets at 31 December 2022 comprise the Group's interest in the Abbeydale appraisal, the Goddard pre-development prospects and Panther and Grafton.

11 Property, plant and equipment

Group

	D&P assets Phase 1 £000	D&P assets Phase 2 £000	Pipeline assets £000	Right of use assets £000	Admin Assets £000	Total £000

Cost						
At 1 January 2021	33,675	7,150	12,597	18,550	637	72,609
Additions in the year[1]	57,959	289	17,487	2,753	17	78,505
Decommissioning asset revisions (note 17) restated	11,613	(17)	(1,948)	-	-	9,648
At 31 December 2021[1]	103,247	7,422	28,136	21,303	654	160,762
Additions in the year	**54,757**	**960**	**5,603**	**22,383**	**60**	**83,763**
Decommissioning asset revisions (note 17)	**10,559**	**(806)**	**4,148**	**-**	**-**	**13,901**
Asset Impairment and write downs	**(43,432)**	**(7,576)**	**-**	**-**	**(52)**	**(51,060)**
At 31 December 2022	**125,131**	**-**	**37,887**	**43,686**	**662**	**207,366**
Depreciation						
At 1 January 2021	-	-	-	(2,376)	(270)	(2,646)
Charge for the year	-	-	-	(14,276)	(163)	(14,439)
At 31 December 2021	-	-	-	(16,652)	(433)	(17,085)
Charge for the year	**(11,694)**	**-**	**(1,494)**	**(15,006)**	**(99)**	**(28,293)**
At 31 December 2022	**(11,694)**	**-**	**(1,494)**	**(31,658)**	**(532)**	**(45,378)**
Net book value						
At 31 December 2022	**113,437**	**-**	**36,393**	**12,028**	**130**	**161,988**
At 31 December 2021	103,247	7,422	28,136	4,651	221	143,677

[1] See Note 1 of the notes forming part of the financial statements for more details on the prior year restatement.

Following completion of the Saturn Banks Reception Facilities (SBRF) at the Bacton terminal in early 2022, the Blythe and Elgood fields commenced production, resulting in depletion and depreciation charge during the year. Depletion charges on gas assets are classified within Cost of Sales (see note 4). Decommissioning asset revisions reflect updated cost estimates for the year (see note 17).

Following the operational delays and disappointing results of the Southwark drilling campaign, which resulted in a downgrade of 2P reserves associated with the field, and the downgrade in Elgood reserves, the Group has tested D&P Phase 1 assets for impairment. For each CGU, the recoverable amount has been determined using the value in use method which constitutes a level 3 valuation within the fair value hierarchy. The recoverable amount is supported by the fair value derived from a discounted cash flow valuation of the 2P production profile. As disclosed in note 1, under 'critical judgements', key estimates include 2P commercial reserves, production profiles, gas price, capital expenditure estimates and discount rate. The 2P reserves downgrade on the Southwark gas field CGU, which represents investment to date in the A-1 and A-2 wells on Southwark, to 10.0 BCF (2021: 71.2 BCF) resulted in a £43.4 million (2021: £nil) impairment to D&P Phase 1 assets. The Directors were satisfied that no further provision for impairment against the remaining carrying value of the D&P Phase 1 assets.

Phase 2 development and production assets (which include Nailsworth and Elland) reserves were reclassified to 2C resources. This resulted in a full impairment of £7.6 million (2021: £nil) for the Phase 2 assets during the year of due to the value in use calculation supported by 2P reserves under the Groups accounting policy (see note 1).

Right of use assets predominantly relate to the Shelf Perseverance drilling rig contract and support vessels. The Group's net share of £7.4 million (2021: £8.0 million) of depreciation of these right of use assets is capitalised to the development & production assets of the Group. Thames pipeline and office right of use assets depreciation is expensed. All leases are accounted for by recognising a right-of-use asset and a lease liability except for:

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

See Note 23 for disclosures around the Group's lease liabilities.

Company

	D&P assets Phase 1 2022 £000	**Right of use assets 2022 £000**	**Admin assets 2022 £000**	**Total 2022 £000**	D&P assets Phase 1 2021 £000	Right of use assets 2021 £000	Admin assets 2021 £000	Total 2021 £000
Cost								
At beginning of the year	**-**	**21,303**	**654**	**21,957**	1,959	18,550	637	21,146
Additions	**-**	**22,383**	**8**	**22,391**	-	2,753	17	2,770
At end of the year	**-**	**43,686**	**662**	**44,348**	1,959	21,303	654	23,916
Depreciation								
At beginning of the year	**-**	**(16,652)**	**(433)**	**(17,085)**	-	(2,376)	(270)	(2,646)
Charge for the year	**-**	**(15,006)**	**(99)**	**(15,105)**	(1,959)	(14,276)	(163)	(16,398)

At end of the year	**-**	**(31,658)**	**(532)**	**(32,190)**	(1,959)	(16,652)	(433)	(19,044)
Net book value								
At 31 December 2022	**-**	**12,028**	**130**	**12,158**				
At 1 January 2022	-	4,651	221	4,872				

Right of use assets predominantly relate to the Shelf Perseverance drilling rig contract and support vessels. The depreciation of these right of use assets is capitalised to the development & production assets of the Group.

Other minor right of use assets include land and property leases of the Company. All leases are accounted for by recognising a right-of-use asset and a lease liability except for:

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

See Note 23 for disclosures around the Company's lease liabilities.

All Company assets were assessed for impairment, but no impairment indicators were identified.

12 Convertible Loans

The table below sets out the opening, movement and closing position of the LOG loan.

	2022 £000	2021 £000
Balance at the beginning of the year	**8,822**	8,037
Unwinding of the discount	**1,000**	1,001
Gain on loan modification	**-**	(216)
	9,822	8,822

The £11.6 million long-term, unsecured, subordinated to other debt the Group holds, non-interest-bearing Loan Note Instrument allows for conversion of the loan into 60,872,631 Ordinary Shares at a strike price of 19 pence per share until maturity. The maturity date of the loan is 23 September 2023 and remained in place during the year.

13 Investments

Company	**Shares in Group companies £000**	**Loans to Group companies £000**	**Total £000**
At cost			
At 1 January 2021	15,486	44,906	60,392
Additions[1]	-	64,735	64,735
At 31 December 2021[1]	15,486	109,641	125,127
Additions	**-**	**63,749**	**63,749**
Repayments	**-**	**(68,933)**	**(68,933)**
At 31 December 2022	**15,486**	**104,457**	**119,943**

[1] *See Note 1 of the notes forming part of the financial statements for more details on the prior year restatement.*

Loans to Group subsidiaries are interest free and repayable on demand. During the year, repayments of £68.9 million were made to the Company from revenues generated by the Group's gas asset and the balance of the Loans are expected to be recovered from future revenues generated by the Group's UK gas assets. At the year end, the Company reviewed the loan balances for impairment. In line with the requirements of IFRS 9, the Company calculated an expected credit loss equivalent to the lifetime expected credit losses using the value in use methodology. The Company reviewed the recoverability scenarios of each loan to subsidiaries. The Company applies no discounting to the expected credit loss calculation as the effective interest rate is considered to be nil as the loans are interest free and payable on demand. For exploration and evaluation assets, estimated discounted cash flows are risk-weighted for costs and future exploration success. After taking into account these scenarios, the Directors believe the carrying value of these loans to be fully recoverable.

The Company's subsidiaries, all registered at 60 Gracechurch Street, London EC3V 0HR, are as follows:

Directly held	Country of incorporation	Area of operation	%
IOG Infrastructure Limited	United Kingdom	United Kingdom	100
IOG North Sea Limited	United Kingdom	United Kingdom	100
IOG UK Ltd	United Kingdom	United Kingdom	100
Avalonia Energy Limited (dormant)	United Kingdom	United Kingdom	100
Held by Avalonia Energy Limited			
Avalonia Goddard Limited (dormant)	United Kingdom	United Kingdom	100
Avalonia Abbeydale Limited (dormant)	United Kingdom	United Kingdom	100
Avalonia Energy Appraisal Limited (dormant)	United Kingdom	United Kingdom	100

All three active subsidiaries are engaged in the business of oil and gas appraisal, development and/or operations in the UK North Sea.

The four dormant companies were incorporated in 2018 and 2019 and have been made available to support any potential Group restructure following refinancing of the Group.

The financial reporting periods for each subsidiary entity are consistent with the Company and end on 31 December.

14 Interests in production licences

As at 31 December 2022, all nine Group UK Offshore Production Licences, were owned 50% by either IOG North Sea Limited or IOG UK Ltd. The Saturn Banks Pipeline PL370 and Bacton Gas Terminal assets are owned 50% by IOG Infrastructure Limited.

15 Trade and other receivables

	2022 £000	2021 £000
Group		
Trade receivables	6,515	-
VAT recoverable	297	1,455
Prepayments	1,920	245
Other receivables	174	5
	8,906	1,705
Company		
VAT recoverable	296	1,455
Prepayments	263	245
Other receivables	9	5
	568	1,705

Trade debtors represent receivable balances for December 2022 gas sales from BP Gas Marketing Limited of £6.5 million (2021: £nil) and for condensate sales from Haltermann Carless UK Limited of £60,000 (2021: £nil). Both amounts were received in January 2023. Prepayments of £1.9 million relate to advance payments made to ODE Asset Management who act as Duty Holder for IOG's operated assets and minor prepayments for other general administrative services.

The Company has considered the carrying value of its trade debtors in the context of IFRS 9 and has assessed the debtors ability to repay the amount due. In assessing the expected credit loss ('ECL') of the receivables, the Company considered expected future cash flows from the counterparties, their creditworthiness, any increase in credit risk, past payment performance and concluded there is no material ECL provision required.

16 Trade and other payables

	2022 £000	2021 £000
Group		
Accruals	**21,080**	11,933
Operator advance accounts	**15,843**	11,728
Lease liabilities	**14,609**	11,068
Trade payables	**11,099**	7,713
Contingent consideration payable	**750**	659
Tax payable	**268**	367
Decommissioning liability	**409**	-
	64,058	43,468

Company		
Lease liabilities	**14,609**	11,068
Trade payables	**11,099**	7,713
Accruals	**850**	1,294
Contingent consideration payable	**750**	659
Tax payable	**268**	367
	27,576	21,101

Current liabilities represent £21.1 million (2021: £11.9 million) of accruals for the value of work carried out under engineering, construction, procurement and commissioning activities and contracts, £15.8 million (2021: £11.7 million) operators advance accounts representing the balance due to JV partners, being the difference between cash calls received and billing statements, £14.6 million (2021: £11.1 million) lease liabilities under IFRS 16 relate to the future payment obligations within the year, £11.1 million (2021: £7.7 million) trade payables of unpaid invoices to various suppliers and service providers, £750,000 (2021: £659,000) contingent consideration for an additional consideration payable 3 months after first gas as part of the acquisition of the Southwark asset, £268,000 (2021: £367,000) Employer tax payable is due to HMRC at end of the year. Elland suspended well decommissioning of £409,000 (2021: £nil) is scheduled to take place in 2023.

Trade and other payables in 2021 have been restated; see note 1 for details.

17 Non-current liabilities

	2022	2021
	£000	£000
Group		
Long-term loans	**97,437**	91,257
Lease liability	**1,273**	395
Deferred tax liability	**11,362**	-
Decommissioning provision	**29,778**	15,837
	139,850	107,489
Company		
Long-term loans	**97,437**	91,257
Lease liability	**1,273**	395
	98,710	91,652

Long-term loans:

The Nordic bond issued on 20 September 2019 represents £87.6 million (2021: £82.4 million) of the long-term loans balance with the LOG loan of £9.8 million being the balance of the total of £97.4 million. See note 22 for further details of the Nordic bond.

The amounts drawn on LOG loans at 31 December 2022 and 31 December 2021 were as follows:

Loan Facility	Entity	Effective Date	Maturity Date	Principal	Interest
£11.6 million convertible loan, 5 year facility	IOG plc	28 September 2019	23 September 2024	£11.6 million	Nil

See note 12 for information relating to the outstanding LOG loan.

Decommissioning provision:

	2022	2021
	£000	£000
At 1 January	15,837	6,226
New provisions and changes in estimates	13,901	9,601
Unwinding of decommissioning provision discount	449	10
Reclassification to short term liability	(409)	-
At 31 December	**29,778**	15,837

The Group provides for the present value of estimated future decommissioning costs for its gas properties in the UK Southern North Sea. These costs are updated annually based upon a review of both estimated cost, inflation and

Southern North Sea. These costs are updated annually based upon a review of both estimated cost, inflation and discount rates. Periodically, the Group will undertake a more detailed technical assessment by both internal and external specialists as appropriate. The amounts shown are expected to crystallise in 2038. The inflation rate used in the calculation of the decommissioning provision at 31 December 2022 was 2.0% (2021: 2.0%). The discount rate used in the calculation of the decommissioning provision at 31 December 2022 was 4.03% (2021: 2.75%).

The reclassification to short term liability relates to the decommissioning for a suspended well on the Elland Licence P039. During 2022, the Elland abandonment scope was reviewed and it was been established that abandonment can be completed using a vessel instead of a rig, which has significantly reduced the costs. The abandonment expenditure was revised to £0.8 million gross (2021: £2.4 million), which is £0.4 million net to the Company (2021: £1.2 million).

18 Net Debt

IOG uses the following definition of net debt - restricted cash and cash equivalents plus the financial asset, less total loans.

	Notes	2022 £000	2021 £000
Restricted cash		**2,564**	3,429
Non-current restricted cash	21	**3,116**	-
Cash and cash equivalents		**26,693**	31,255
Loans		**(97,437)**	(91,257)
Net debt		**(65,064)**	(56,573)

19 Share capital

	Number	Share capital £000	Share premium £000	Total £000
Authorised, allotted, issued and fully paid				
At 1 January 2021				
- Ordinary Shares of 1p each	**488,211,155**	**4,882**	**49,989**	**54,871**
Equity issued:				
- September 2021, Ordinary Shares of 1p,[1]	33,800,000	338	8,112	8,450
- Other LTIP and Salary sacrifice share exercises	1,753,057	18	48	66
	523,764,212	**5,238**	**58,149**	**63,387**
At 31 December 2021	**523,764,212**	**5,238**	**58,149**	**63,387**
- Ordinary shares of 1p each				
Equity issued:				
- Other LTIP and Salary sacrifice share exercises	1,273,141	12	24	36
At 31 December 2022	**525,037,353**	**5,250**	**58,173**	**63,423**
- Ordinary Shares of 1p each				

[1] *During 2021, the Company carried out a share placement of 33,800,00 at 25 pence per share.*

20 Share based payments

IOG plc operates a Company Share Option Plan (CSOP) under which all its share options are granted. The Company has outstanding share options issued which are not exercised under previously established plans that are no longer used by the Company. The following expenses have been recognised for share option grants under the Company's CSOP in the Statement of Comprehensive Income arising on share-based payments and included within administrative expenses:

2022	2021
£000	£000

Share based payment charge	**844**	1,284

The Company granted the following share options under its share option plans as follows:

	Number	Price	Date of Grant	Expiry
1 January 2021	**25,290,322**	**7.70p**		
Salary/fee sacrifice options	972,685	1p	28 Feb 2021	28 Feb 26
CSOP cancelled/expired	(3,175,284)	1p		
CSOP options	9,199,640	1p	Various dates in 2021	Various dates in 2031
Salary/fee sacrifice options	479,052	1p	31 Aug 2021	28 Sept 26
Options exercised	(2,072,252)			
31 December 2021	**30,694,163**	**6.53p**		
CSOP cancelled/expired	(1,596,434)	1p		
CSOP options	5,580,328	1p	Various dates in 2022	Various dates in 2032
Options exercised	**(1,273,141)**			
31 December 2022	**33,404,916**	**4.98 p**		

Of the remaining staff options, 33,404,916 outstanding at 31 December 2022, 1,273,141 were exercised during the year, 5,580,328 issued and 1,596,434 have been cancelled. Of the remaining staff options, 30,694,163 outstanding at 31 December 2021, 2,072,252 were exercised during the year and 3,175,284 have been cancelled. The fair value of these options exercised was transferred from the Share-based Payment Reserve to Accumulated Loss.

All salary/fee sacrifice options outstanding at 31 December 2022 were issued at an exercise price of 1p per share and carry no additional performance conditions. These shares were issued at a volume calculated by taking the amount owing and dividing by the volume weighted average price for the period to which the salary/fee sacrifice pertains.

CSOP Valuation

The 2022 CSOP valuation is based on a Log-normal Monte-Carlo stochastic model. The valuation model assumes:

	11 November 2022	**17 March 2022**	2021
	£000	**£000**	£000
Share price at date of grant	**12.40p**	**37.70p**	22.50p
Exercise price	**1.00p**	**1.00p**	1.00p
Option life	**10 years**	**10 years**	10 years
Risk-free rate	**3.23%**	**1.31%**	0.17%
Share price volatility	**76.35%**	**55.71%**	64.56%
Iterations	**10,000**	**10,000**	10,000

All share options outstanding at 31 December 2022 were issued to option holders with, other than the target price, several non-market based performance criteria. Non-market based performance criteria included the delivery, measurement, control and management of an appropriate HSE statement and policy together with a Group-wide HSE focussed culture.

The remaining average contractual life of the 33,404,916 options outstanding at 31 December 2022 (2021: 30,694,163) was 3.2 years at that date (2021: 4.2 years) of which 5,798,288 were exercisable at 31 December 2022 (2021: 4,480,836).

The weighted average exercise price of the options remaining was 4.98p at 31 December 2022 (2021: 6.53p).

Further details for Directors are provided on pages 26 and 27.

The Company did not grant any warrants in the current year (2021: nil). No warrants were exercised during the year (2021: nil) and no warrants lapsed during the year (2021: nil) and are shown as follows:

	Number	Price	Date of Grant	Expiry
1 January 2022	[illegible]	[illegible]	12/09/2018	31/08/2023

1 January 2022	**20,000,000**	**32.18p**	13/09/2018	31/08/2023
31 December 2022	**20,000,000**	**32.18p**	13/09/2018	31/08/2023

The fair value of 20,000,000 warrants granted to London Oil & Gas Limited on 13 September 2018 was calculated using the Black-Scholes option pricing model, as £4.2 million, all of which was recognised as an issue cost of the £15 million LOG loan facility, held at amortised cost using the effective interest method. The exercise price of these warrants was determined as 32.18p.

The following assumptions were applied in the LOG warrant award calculation:

Risk free interest rate	1.50%
Dividend yield	nil
Weighted average life expectancy	4 years
Volatility factor	96.45%

A volatility of 96.45% has been applied based upon the Company's share price over the period from the Company's listing on AIM on 30 September 2013 until 13 September 2019.

The remaining average contractual life of the 20,000,000 warrants outstanding at 31 December 2022 (2021: 20,000,000) was 0.66 years at that date (2021: 1.66 years). All such warrants were exercisable at 31 December 2022.

The weighted average exercise price of the warrants remaining was 32.18p at 31 December 2022 (2021: 32.18p). No further warrants have been issued or exercised as at 16 March 2023.

21 Restricted cash, Cash and cash equivalents

	2022	2021
Group	**£000**	£000
Restricted cash - Long term	**3,116**	-
Restricted cash - Short term	**2,564**	3,429
Cash at bank	**26,693**	31,255
Company		
Restricted cash	**2,564**	2,066
Cash at bank	**26,693**	31,255

Restricted cash at 31 December 2022 includes £2.6 million (2021: £3.4 million) of restricted deposits in a Euro-denominated Debt Service Reserve Account following the Norwegian Bond issue and a £3.1 million (2021: £1.4 million) deposit secured against decommissioning provisions of its infrastructure assets. Restricted cash balances of £2.6 million for the Group and £2.6 million for the Company are available within 1 year.

Cash and cash equivalents comprise cash in hand, deposits and other short-term money market deposit accounts that are readily convertible into known amounts of cash. The fair value of cash and cash equivalents is £26.7 million (2021: £31.3 million).

22 Bonds payable

On 20 September 2019, the Company issued €100 million Norwegian Bonds on the Oslo Børs to fund the Phase 1 development program.

	2022	2021
	£000	£000
Balance at the beginning of the year	**82,436**	87,777
Amortisation of transaction fees	**560**	560
Interest charged	**8,452**	8,253
Interest Paid	**(8,452)**	(8,253)
Currency revaluation	**4,620**	(5,901)
	87,616	82,436

The secured callable bonds were issued on 20 September 2019 by IOG plc at an issue price of par. The bonds have a term of five years and will be repaid in full at maturity. The bonds carry a coupon of 9.5% plus 3 month EURIBOR with a EURIBOR floor of 0% and were issued at par. The Bond is callable 3 years after issuance with an initial call premium of 50% of the coupon (i.e. repayable at a cost of €104.75 million if 3 month EURIBOR is at zero or lower), declining by 10% every six months thereafter.

Bond covenants

- Minimum liquidity of €2 million up to, and including, six months from the first gas date and €5 million thereafter at all times.
- Minimum leverage ratio of 2.5:1 from the first reporting date following six months after the first gas date.
- Minimum interest cover ratio of five times cover of interest to EBITDA from the first reporting date following six months after the first gas date.

As at 31 December 2022, the ratio of net debt to EBITDA at 31 December 2022 was 1.1 times and interest cover was 7.0 times. Full terms and conditions of the Bonds can be seen in 'Bond Terms' document which is publicly available at: https://www.iog.co.uk/media/1237/bond-terms-execution-version-190919.pdf

23 Lease liabilities

	2022	2021
	£000	£000
Current		
At 1 January	**11,068**	13,781
Interest expenses	**1,882**	1,754
Lease payments	**(18,608)**	(12,307)
Additions	**20,267**	7,840
At 31 December	**14,609**	11,068
Long term		
At 1 January	**395**	4,968
Additions	**941**	395
Move to current	**(63)**	(4,968)
At 31 December	**1,273**	395

Lease payments represent the Group and Company's share of Drilling Rig rental, PSV marine supply vessel rental, ERV marine emergency rapid response vessel rental, office lease rental payments at the London and Norwich offices, together with the Crown Estate lease for the rights for the Saturn Banks Pipeline to cross the foreshore at Bacton. During 2022, the Company continued with drilling rig contract with Shelf Drilling (UK) Ltd (contract transferred from Noble Corporation during the year) for the Noble Hans Deul jack-up drilling rig (to be renamed the Shelf Perseverance) for which payments commenced in 2021 and therefore subsequently continued with both the marine supply vessel and marine emergency rapid response vessel. Additionally, in 2022 the Company entered a lease for the Norwich office.

24 Financial instruments

Significant accounting policies

Details of the significant accounting policies in respect of financial instruments are disclosed in Note 1 of the financial statements.

Financial risk management

The Board seeks to minimise its exposure to financial risk by reviewing and agreeing policies for managing each financial risk and monitoring them on a regular basis. At this stage, no formal policies have been put in place to hedge the Group and Company's activities to the exposure to currency risk or interest risk and no derivatives or hedges were entered during the year.

General objectives, policies and processes

The Board has overall responsibility for the determination of the Group and Company's risk management objectives and policies and, whilst retaining ultimate responsibility for them, it has delegated the authority for designing and operating processes that ensure the effective implementation of its objectives and policies to the Group's finance function. The Board receives regular reports from the Chief Financial Officer through which it reviews the effectiveness of the processes put in place and the appropriateness of the objectives and policies it sets.

The Group is exposed through its operations to the following financial risks:

- Liquidity risk;
- Credit risk;
- Commodity price risk;
- Cash flow interest rate risk; and
- Foreign exchange risk

The overall objective of the Board is to set policies that seek to reduce risk as far as possible without unduly affecting the Group and Company's competitiveness and flexibility. Further details regarding these policies are set out below.

Principal financial instruments

The principal financial instruments used by the Group and Company, from which financial instrument risk may arise are as follows:

- Cash and cash equivalents
- Restricted cash
- Loans
- Other financial assets
- Trade and other receivables
- Trade and other payables
- Bonds

Liquidity risk

The Group and Company's policy is to ensure that it will always have sufficient cash to allow it to meet its liabilities when they become due. To achieve this aim, it seeks to maintain readily available cash balances supplemented by borrowing facilities sufficient to meet expected requirements for a period of at least twelve to eighteen months for personnel costs, overheads, working capital and as commitments dictate for capital spend.

Rolling cash forecasts, which are essentially the current budgeting and reforecasting process, identifying the liquidity requirements of the Group and Company, are produced frequently. These are reviewed and approved regularly by management and the Board to ensure that sufficient financial resources are made available. The Group's oil and gas exploration and development activities are currently funded through the Company with existing cash balances, operating cash flow generated in the period and joint venture partner cash call receipts from CER.

	6 months or less	Greater than 6 months, less than 12 months	Greater than 12 months	Total undiscounted	Carrying amount
2022 Group	**£000**	**£000**	**£000**	**£000**	**£000**
Current financial liabilities					
Trade and other payables	11,098	-	-	11,098	11,098
Lease liability	-	14,609	-	14,609	14,609
Accruals	21,077	-	-	21,077	21,077
Deferred consideration	750	-	-	750	750
Non-current financial liabilities					
Loans	-	-	11,566	11,566	9,822
Lease liability	-	-	1,273	1,273	1,273
Deferred tax liability	-	-	11,362	11,362	11,362
Bonds	5,171	5,200	96,398	106,769	87,615
	38,096	19,809	120,599	178,504	157,606
2021 Group					
Current financial liabilities					
Trade and other payables	7,708	-	-	7,708	7,708
Lease liability	10,372	1,083	-	11,455	11,068
Accruals	13,345	-	-	13,345	13,345
Non-current financial liabilities					
Deferred Consideration	-	750	-	750	659
Loans	-	-	11,566	11,566	8,821
Lease liability	-	-	414	414	395
Bonds	4,034	4,034	97,485	105,554	82,435

	35,459	5,867	109,465	150,792	124,431

2022 Company	6 months or less £000	Greater than 6 months, less than 12 months £000	Greater than 12 months £000	Total undiscounted £000	Carrying amount £000
Current financial liabilities					
Trade and other payables	11,098	-	-	11,098	11,098
Lease liability	-	14,609	-	14,609	14,609
Accruals	828	-	-	828	828
Deferred consideration	750	-	-	750	750
Non-current financial liabilities					
Loans	-	-	11,566	11,566	9,822
Lease liability	-	-	1,273	1,273	1,273
Bonds	5,171	5,200	96,398	106,769	87,615
	17,847	19,809	109,237	146,893	125,995
2021 Company					
Current financial liabilities					
Trade and other payables	7,708	-	-	7,708	7,708
Deferred Consideration	10,372	1,083	-	11,455	11,068
Accruals	2,723	-	-	2,723	2,723
Non-current financial liabilities					
Deferred Consideration	-	750	-	750	659
Loans	-	-	11,566	11,566	8,821
Lease liability		-	414	414	395
Bonds	4,034	4,034	97,485	105,554	82,435
	24,837	5,867	109,465	140,170	113,809

Credit risk

Credit risk arises principally from the Group's and Company's trade and other receivables, restricted cash, cash and cash equivalents, and loans to subsidiaries (Company). It is the risk that the counterparty fails to discharge its obligation in respect of the instrument. The credit risk on liquid funds is limited because the counterparties are banks with credit ratings assigned by international credit rating agencies. The Group places funds only with selected organisations with ratings of 'A' or above as ranked by Standard & Poor's for both long and short-term debt. Funds are currently placed with the National Westminster Bank plc and DNB Bank ASA for the DSRA. Under IFRS 9 there is no material impact for both the Group and Company when assessing expected credit losses of its receivables.

The Group made investments and advances into subsidiary undertakings during the year and these mostly relate to the funding of the SNS Hub Development Projects, and the Company commenced recovery of these loans in the period from production from the Blythe and Elgood gas fields held by IOG North Sea Limited. The Company expects to recover the outstanding loans through future gas sales under the licences held by its subsidiaries from current and future developments. Loans to subsidiary undertakings are recognised at amortised cost in accordance with IFRS 9. The loans have no maturity date and are not repayable until the respective subsidiary entity has sufficient cash to repay the loan. The Board has accordingly assessed the expected repayment dates based on the strategic forecasts approved by the Board.

As at the reporting date, the Group had £9.0 million external receivables (2021: £nil).

IFRS 9 introduced a new impairment model that requires the recognition of ECLs on financial assets at amortised cost. The ECL computation considers forward looking information to recognise impairment allowances earlier. In accordance with IFRS 9, the Group calculated its ECL based on its exposure to credit risk on its trade receivables at the end of the year and did not recognise an ECL (see note 15). Intercompany exposures, where appropriate, are also in scope under IFRS 9. The Company assesses the loans made to subsidiary undertakings on the basis of the relevant subsidiaries' long-term strategic forecasts and alongside the Board's commercial rationale for providing the specific loan. The loans are not repayable on demand and are expected to be repaid once the underlying assets progress into the production phase when cash inflows are generated. Based on the methodology set out by the standard, the Board has for each intercompany loan, assessed the probability of the default, the loss given default and the expected exposure to compute the ECLs. The Board has incorporated relevant medium and long-term macroeconomic forecasts in their assessment which is included as a principle consideration in the entity's strategic forecasts. Such factors include gas price sensitivities, funding requirements, reserve and resource estimates. The Board has concluded that any ECLs to be recognised are not material to these financial statements. Accordingly, the Company has not recognised any expected credit loss for the balances owed by subsidiary undertakings recognised on the Balance Sheet at amortised cost. The Group and Company do not hold any collateral as security for any external financial instruments, or otherwise.

The maximum exposure to credit risk is the same as the carrying value of these items in the financial statements as shown below.

	Group		Company	
	2022 £000	2021 £000	**2022 £000**	2021 £000
Trade receivable	**6,515**	-	**-**	-
Other receivables	**2,454**	1,445	**568**	1,705
Loans to subsidiaries	**-**	-	**104,457**	109,641
Restricted cash	**5,680**	3,429	**2,564**	2,066
Cash and cash equivalents	**26,693**	31,255	**26,693**	31,255

Commodity price risk

The Group currently has not entered into any commodity price hedging instruments. The Group does occasionally fix month ahead gas prices under its Gas Sales Agreement over a portion of its production for which it is not required to post collateral. As at 31 December 2022, the Group had fixed the gas price for January at 319 pence per therm for 30,000 therms of its daily production.

The Group commenced gas production during the year. The Group's asset valuations and cash flow modelling make assumptions on the anticipated gas price for the period of expected production. The Group uses a seasonally adjusted flat pricing structure that is not inflated over the expected production life of the asset.

Cash flow interest rate risk

The Group's exposure to interest rate risk arises from its Bond (see note 22) and restricted cash, cash and cash equivalents. The Group has a €100 million Bond that carries a coupon of 9.5% plus 3 month EURIBOR with a EURIBOR floor of 0%. An increase of 100 basis points or a decrease of 25 basis points in interest rates at the reporting date would have had the following effect on the income statement for the Group and Company. This analysis assumes all other variables, in particular foreign currency, remain constant.

	100 bps increase 2022 £000	**25 bps decrease 2022 £000**	100 bps increase 2021 £000	25 bps decrease 2021 £000
Restricted cash	**57**	**(14)**	34	(9)
Cash and cash equivalents	**267**	**(67)**	313	(78)
Long-term loans	**(886)**	**221**	(840)	210

The other financial instruments of the Group that are not included in the above tables are non-interest bearing and are therefore not subject to interest rate risk.

Foreign exchange risk

The Group is exposed to foreign currency risk arising from movements in currency exchange rates. Such exposures arise predominantly from purchases in currencies other than the Group's functional currency and the Bond which is denominated in Euros. In relation to the euro denominated Bond and cash held in DSRA, a 5% strengthening or weakening in the value of euro against sterling would result in an decrease by £4.5 million or an increase by £4.1 million.

The Company cash balances, included restricted cash, are held in GBP £23.8 million, EUR €8.6 million and USD $1.2 million. This exposure gives rise to net currency gains and losses recognised in the Statement of Comprehensive Income. A 5% fluctuation in the GBP sterling rate compared to EUR would give rise to a £0.4 million gain or £0.4 million loss in the Group and Company's Statement of Comprehensive Income.

The Group has two current revenue streams. Gas sales are contracted to BP Gas Marketing Limited and denominated in GBP. Condensate sales are contracted to Haltermann & Carless UK Limited and are denominated in USD. Condensate sales represent 5% of total sales of £75.4 million (2021: £nil). The Group and the Company's cash balances are maintained primarily in GBP Sterling (which is the functional and reporting currency of each Group company) and EUR for the Bond DSRA with small balances held in USD to settle any USD liabilities. No formal contracts have been put in place to hedge the Group and Company's activities to the exposure to currency risk. It is the Group's policy to ensure that individual Group entities enter transactions in their functional currency wherever possible. The Group considers this minimises any foreign exchange exposure.

Management regularly monitor the currency profile and obtain informal advice to ensure that the cash balances are held in currencies which minimise the impact on the results and position of the Group and the Company from foreign exchange movements.

Capital management

The primary objective of the Group's capital management is to maintain appropriate levels of funding to meet the commitments of its forward programme of appraisal and development expenditure, and to safeguard the entity's ability to continue as a going concern and create shareholder value. The Director's consider capital to include equity as described in the Statement of Changes in Equity, and loan notes, as disclosed in Notes 12 and 22.

The Group manages compliance of the Bond and the covenants by reviewing on a monthly basis its cash flow modelling which incorporates the bond terms and covenants. Norwegian advisors are also engaged to ensure that any regulatory requirements are met. At each reporting date the Directors provide representation that the terms of the bond are satisfied.

25 Financial commitments and contingent liabilities

The Group had outstanding commitments of £5.7 million gross to the joint operations (the Group's net share is £2.8

million) as at 31 December 2022. All 2022 committed amounts relate to contracted service awards to suppliers procured for the development and operation of the Group's phase 1 project assets (Blythe, Southwark, Elgood, Saturn Banks Facilities and Saturn Banks Pipeline).

Under the terms of the licences to explore for gas, the Company has certain commitments that are generally defined by activity rather than expenditure requirements. The Goddard and Kelham appraisal wells have been approved by the joint operating committee operated by the Group in a 50%/50% joint arrangement, and these appraisal wells are committed to be drilled by 30 September 2023 under the current licence terms.

Saturn Banks Pipeline System:

Security in the sum of £0.5 million, the Initial Saturn Banks Pipeline Decommissioning Security Amount (DSA), was provided on completion of the Saturn Banks Pipeline SPA in April 2018. In October 2019, following the completion of the farm-out to CER, this amount was reduced to £0.25 million.

Further security in the sum of £1.8 million was transferred during 2022 to the Saturn Banks Pipeline Decommissioning Security Amount. The total security held is £3.1 million (2021: £1.4 million)

Saturn Banks Reception Facilities ("SBRF"):

Security in the sum of £2.0 million, the Initial SBRF Decommissioning Security Amount, was provided on completion of the SBRF SPA in October 2019. Following the completion of the farm-out to CER, this amount was reduced to £1.0 million.

Further security in the sum of £4.0 million, the SBRF Decommissioning Security Amount, is to be provided 2.5 years following the announcement of 'first gas'. This additional amount is payable in 8 quarterly instalments of £0.5 million with the first instalment payable 6 months after the declaration of 'first gas'. During the year, £1.8 million was transferred into security deposit account to meet the requirement of SBRF Decommissioning Security Agreement.

Cross-Guarantees:

The Company acts as guarantor to its subsidiary IOG North Sea Limited and its facilities with LOG. These cross guarantees are considered insurance contracts in accordance with IFRS 4.

26 Related party transactions

Details of Directors' and key management personnel remuneration are provided in Note 4.

Rupert Newall, CEO, and persons closely associated, at 31 December 2022 held 4,953,921 ordinary shares of 1p each in the capital of the Company. Rupert was also the current holder of 5,570,461 share options at 31 December 2022.

Dougie Scott, COO, at 31 December 2022 held 192,289 ordinary shares of 1p each in the capital of the Company. Dougie was also the current holder of 1,690,141 share options at 31 December 2022.

Fiona MacAulay, Chair, at 31 December 2022 held 269,178 ordinary shares of 1p each in the capital of the Company. Fiona is also the current holder of 1,000,000 share options at 31 December 2021. Fiona is also entitled to 109,865 share options through salary sacrifice at 31 December 2022.

Esa Ikaheimonen, Non-Executive Director, at 31 December 2022 held 500,000 ordinary shares of 1p each in the capital of the Company. Esa is also the current holder of 600,000 share options at 31 December 2022. Esa is also entitled to 868,306 share options through salary sacrifice at 31 December 2022.

Neil Hawkings, Non-Executive Director, at 31 December 2022 held 20,000 ordinary shares of 1p each in the capital of the Company. Neil is also the current holder of 600,000 share options at 31 December 2022. Neil is also entitled to 72,999 share options through salary sacrifice at 31 December 2022.

Details of loans and interest charged (only relevant to 2019) by LOG are detailed in Note 12. The relevant loans outstanding at the end of the year related to the Company.

27 Notes supporting statements of cash flows

Details of significant non-cash transactions

	2022	2021
	£000	£000
Equity consideration for settlement of liabilities	**-**	-

Group - Loans and borrowings

	Current loans and borrowings £000	Non-current loans and borrowings £000	**Total loans and borrowings £000**
At 1 January 2021	13,781	13,005	26,786
Lease Liability additions	7,840	395	8,235
Repayments	(12,307)	-	(12,307)
Unwinding of discount	1,754	785	2,539
Move to current loans & borrowings	-	(4,968)	(4,968)
At 31 December 2021	11,068	9,217	20,285
Lease Liability additions	**20,267**	**877**	**21,157**
Repayments	**(18,608)**	**-**	**(18,608)**
Unwinding of discount	**1,882**	**1,001**	**2,871**
Move to current loans & borrowings	**-**	**-**	**-**
At 31 December 2022	**14,609**	**11,095**	**25,705**

Company - Loans and borrowings

	Current loans and borrowings £000	Non-current loans and borrowings £000	**Total loans and borrowings £000**
At 1 January 2021	13,781	13,005	26,786
Lease Liability additions	7,840	395	8,235
Repayments	(12,307)	-	(12,307)
Unwinding of discount	1,754	785	2,539
Move to current loans & borrowings	-	(4,968)	(4,968)
At 31 December 2021	11,068	9,217	20,285
Lease Liability additions	**20,279**	**877**	**21,157**
Repayments	**(18,608)**	**-**	**(18,608)**
Unwinding of discount	**1,870**	**1,001**	**2,871**
Move to current loans & borrowings	**-**	**-**	**-**
At 31 December 2022	**14,609**	**11,095**	**25,705**

28 Subsequent events

On 5 March 2023, the Blythe H2 well spudded, intended to increase gas production, limit water production and maximise reserve recovery from the Blythe reservoir

On 24 February 2023, the Company announced, Fiona MacAulay, who has been Chair of IOG since December 2018 having first joined the Board in July 2018, has chosen not to stand for re-election as a director of the Company at the 2023 Annual General Meeting (AGM), which is expected in May. She will therefore be retiring as Chair and resigning as a Director following the AGM. It is the Board's intention that, following the AGM, Esa Ikaheimonen will become Chair of IOG initially on an interim basis. Esa has been the Senior Independent Non-Executive Director at IOG since March 2019 and is the current Chair of the Audit Committee.

On 6 February 2023, the Company announced the decision to suspend the Southwark A2 well following the remediation programme that although successfully reduced water production from 1,500 bbls/d to an average rate of 380 bbl/d, stabilised gas rates were limited to 2.5 mmscf/d, at a flowing wellhead pressure of 1186 psi. and evaluate the feasibility of cycled production and alternative longer-term remediation strategies.

On 12 January 2023, the Group submitted for nine Southern North Sea blocks across five licences areas in the 33rd UK Offshore Licensing Round, as operator of the 50:50 joint venture with CER.

END

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