30 March 2022

Gulf Keystone Petroleum Ltd. (LSE: GKP)
(“Gulf Keystone”, “GKP”, “the Group” or “the Company”)

2021 Full Year Results Announcement

Gulf Keystone, a leading independent operator and producer in the Kurdistan Region of Iraq, today announces its results for the full year ended 31 December 2021.

Jon Harris, Gulf Keystone's Chief Executive Officer, said:

“I am pleased to report a year of strong operational and financial delivery in 2021. With a 19% increase in gross average production to 43,440 bopd, our leverage to the recovery in oil prices and continued cost and capital discipline, we generated substantial revenue and free cash flow.

We continued to deliver on our strategy of balancing investment in sustainable growth and shareholder returns, as we resumed drilling activities and submitted a draft Field Development Plan to the Ministry of Natural Resources while also returning $100 million of dividends to our shareholders in 2021. Following the $50 million dividend that we paid in February 2022, we are pleased to announce today the declaration of an additional $90 million of dividends. This brings aggregate shareholder distributions declared since 2019 to $340 million.

Looking ahead to the remainder of 2022, we remain focused on delivering gross annual production of 44,000-50,000 bopd by bringing SH-15 online in Q2 2022 and optimising production with well interventions and workovers. While constructive engagement continues with the MNR on the FDP, timing of approval remains uncertain and further progress is required before we fully execute FDP activity.

Following my first year as GKP’s CEO, I would like to personally thank the Company’s teams in Kurdistan and the UK for all of their efforts. We are in a strong position and I am excited about safely delivering the significant growth potential of the Shaikan Field to drive sustainable value for all of our stakeholders.”

Highlights to 31 December 2021 and post reporting period

Operational

- Continued strong focus on safety in 2021 despite one previously reported lost time incident ("LTI"); currently no LTIs recorded for over 160 days
- Third consecutive year of production growth with 2021 gross average production of 43,440 bopd, towards the upper end of our tightened guidance range of 42,000-44,000 bopd and a 19% increase versus 2020
- 2022 YTD gross average production of c.45,500 bopd, following milestone achievement in February 2022 of 100 MMstb cumulative production since inception
- Successfully restarted drilling activities in June, resulting in two new wells, SH-13 and SH-14, coming online towards the end of the year
- After acid stimulations, current SH-13 production in line with expectations while we continue to explore options to further increase SH-14 production
- Following the early appearance of trace quantities of water, SH-12 is currently shut-in while we investigate near-term production options ahead of installation of planned water handling facilities
- Spudded SH-15, which is currently being hooked up ahead of targeted start-up in Q2 2022

Draft Shaikan Field Development Plan (“FDP”)

- Submitted draft FDP to Ministry of Natural Resources in November 2021 comprising plan to increase Phase 1 gross production plateau to between 85,000-95,000 bopd while eliminating routine flaring and significantly reducing carbon intensity
- While final timing of approval remains uncertain due to the complexity of the project, we are providing today an interim update on progress to date on Phase 1 of the draft FDP. As we continue to review opportunities to further optimise the project, final details and cost estimates may vary and we expect to provide an update upon FDP approval

- Expected components of Phase 1 of draft FDP:
  - Expand Jurassic gross production plateau up to 85,000 bopd
  - Test Triassic reservoir, targeting gross production plateau of up to 10,000 bopd
  - Concurrently, execute Gas Management Plan to eliminate routine flaring through gas reinjection, underpinning target of more than halving scope 1 and 2 emissions per barrel by 2025
- From FDP approval, expected duration of Phase 1 Jurassic and Triassic projects is 36 to 42 months and the Gas Management Plan is 18 to 24 months
- Total Phase 1 gross Capex currently estimated to be $800-$925 million, up c.$160 million from previous FDP with the objective of increasing production towards 95,000 bopd through project optimisations

Financial

- Strong free cash flow generation of $122.2 million (2020: $(22.9) million)
- Total dividends of $100 million paid in 2021, including a 2020 annual dividend of $25 million, a special dividend of $25 million and an interim dividend for 2021 of $50 million. An additional $50 million interim dividend was paid to shareholders in February 2022
- Revenue almost tripled to $301.4 million (2020: $108.4 million), contributing to a return to profit after tax of $164.6 million (2020: $47.3 million loss)
- Adjusted EBITDA increased by almost four times to $222.7 million (2020: $56.7 million) driven by higher gross production, leverage to the recovery in oil prices and the Company's continued strict control of costs:
  - Gross average production increased 19% to 43,440 bopd (2020: 36,625 bopd)
  - Realised price more than doubled to $49.7/bbl (2020: $20.9/bbl)
  - Gross Opex per barrel of $2.7/bbl (2020: $2.6/bbl), in line with 2021 guidance of $2.5-$2.9/bbl
- Revenue receipts of $221.7 million in 2021 from the KRG for crude oil sales related to the December 2020 to August 2021 invoices and partial repayment of arrears related to the outstanding November 2019 to February 2020 invoices
- Since the beginning of 2022, the Company has received a further $106.4 million net to GKP for crude oil sales and arrears related to the September 2021 to November 2021 invoices. As at 29 March 2022, the outstanding arrears balance is $21.9 million net to GKP
- Net Capex of $50.8 million (2020: $45.9 million), primarily related to the completion of the SH-13 and SH-14 wells and debottlenecking of PF-2
- Robust cash balance of $182.7 million at 29 March 2022

Outlook

- Remain focused on delivering 2022 gross average production of 44,000-50,000 bopd reflecting the anticipated production contribution from SH-15 and the benefits of well intervention and workover activities
- 2022 net capital expenditure guidance of $85-$95 million:
  - Includes completion of SH-15 drilling, well interventions and workovers, and activity that enables us to expedite the FDP following approval
  - With progress on the FDP, the Company expects to resume drilling and increase 2022 capital guidance
- Gross Opex guidance of $2.9-$3.3/bbl, driven by increased operational activity and the continued catch up of previously scheduled work programmes deferred due to COVID-19
- Today declaring $90 million of dividends, representing further delivery against GKP's strategic commitment of balancing investment in sustainable growth with shareholder returns:
  - $25 million final 2021 ordinary dividend subject to approval at AGM on 24 June 2022
  - $65 million interim dividend, expected to be paid on 13 May 2022, based on a record date of 29 April 2022 and ex-dividend date of 28 April 2022
  - The Company will disclose the US dollar and pounds sterling rate per share for both dividends prior to their ex-dividend dates
- Assuming timely payment of invoices and continuing strong oil prices, we are expecting strong cash flow generation in 2022. This would provide flexibility to fund a potential increase in capital expenditure, with progress on the FDP, and the opportunity for further distributions to shareholders, while preserving adequate liquidity and maintaining a robust balance sheet

Investor & analyst presentation

Gulf Keystone's management team will be presenting the Company's 2021 Full Year Results at 10:00am (BST) today via live audio webcast:

https://webcasting.brrmedia.co.uk/broadcast/6221e42cfa16d9059b846ad1

This announcement contains inside information for the purposes of the UK Market Abuse Regime.

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Notes to Editors:

Gulf Keystone Petroleum Ltd. (LSE: GKP) is a leading independent operator and producer in the Kurdistan Region of Iraq. Further information on Gulf Keystone is available on its website www.gulfkeystone.com

Disclaimer

Chairman's statement

2021 was characterised by both an improvement in the oil price and operational environment. The price of Dated Brent averaged $71/bbl in the year, up $29/bbl versus the 2020 average, driven by the partial recovery of global demand and the continued regulation by OPEC+ of supply. At the same time, COVID-19 restrictions gradually loosened, with a return to more normal working patterns in the Field. Having taken rapid action in 2020 to protect staff, reduce costs and preserve liquidity, the Company was able to capitalise on these better conditions.

Since the beginning of the year, the price of Brent Crude has continued to increase, although it remains volatile. While the improvement in oil price drives increased cash flow, I and the Board are deeply concerned about the primary reason for the increase, the invasion of Ukraine. Our thoughts are with the many Ukrainian citizens who have had to flee their homes or have lost their lives due to the conflict.

In 2021, Gulf Keystone generated significant cash flow due to its strong leverage to the recovery in oil price, increased production and continued cost and capital discipline. In line with the Company's strategy of balancing investment in sustainable growth with shareholder distributions, in March 2021 the Board reinstated the Company's dividend policy of paying at least $25 million annually to shareholders. Total dividends of $100 million were subsequently paid in 2021, given continuing strong oil prices and cash generation.

Since the beginning of 2022, Gulf Keystone has paid a $50 million interim dividend and we are pleased to have declared $90 million of additional dividends, comprising a $25 million 2021 annual ordinary dividend for shareholder approval at the Company's AGM on 24 June 2022 and a $65 million interim dividend payable in May 2022. Including these, prior dividends and $50 million of share buybacks, since 2019 the Company has distributed $340 million to shareholders.

Capitalising on a strong balance sheet and improving operating conditions, the Company also resumed investment in the Shaikan Field, restarting drilling activities ahead of schedule in June and bringing two new wells, SH-13 and SH-14, onstream by the end of the year. The Company also resumed engagement with the MNR on Gulf Keystone's vision to develop the Shaikan Field's almost 800 MMstb of 2P reserves and 2C resources, resulting in the submission of a draft Field Development Plan towards the end of 2021.

Phase 1 of the draft FDP is expected to enable Gulf Keystone to increase gross production plateau to between 85,000-95,000 bopd while reducing carbon intensity per barrel by over 50% through the implementation of a Gas Management Plan. We are committed to ensuring the FDP generates significant value for all of Gulf Keystone's stakeholders. We continue to actively engage the MNR to obtain approval of the draft FDP and in the meantime have focused our capital expenditure programme for 2022 on production, safety and preparatory activities.

Sustainability continues to be a strategic focus for the Board, which is supported by Gulf Keystone's Safety and Sustainability Committee. With the submission of the draft FDP, the Board was pleased to see the Company's Gas Management Plan, and its objectives of reducing carbon intensity and eliminating routine flaring, move a step closer. The Company also continued to make significant social and economic contributions to Kurdistan through local employment and community engagement programmes, local supply chain investment and generation of revenues from the field for our host government, the KRG.

The Board continued to engage with Gulf Keystone's shareholders in 2021, both at the Annual General Meeting and on a more frequent basis with the Company's major shareholders. We welcome ongoing engagement and feedback from all investors and encourage all GKP shareholders to participate in our 2022 AGM. This year, the Company's remuneration policy will be subject to a binding shareholder vote at the AGM. The Board has made minor changes to the current policy, which was approved at the 2019 AGM with support in excess of 98%.

The only change to the Board over the last year was the appointment of Jon Harris as Gulf Keystone's new CEO in January 2021. Jon has been instrumental in successfully resuming investment in the Shaikan Field and advancing negotiations with the MNR as we seek approval of the FDP.

On behalf of the Board, I would like to thank Jon, the rest of the leadership team and all of Gulf Keystone's employees for another strong year of operational and financial delivery. In addition, I would like to thank all of our stakeholders for their ongoing support. We are excited about the future and we look forward to further progress in driving sustainable growth and value from the Shaikan Field for the benefit of all of Gulf Keystone's stakeholders.

Jaap Huijskes
Non-Executive Chairman

CEO review

I am pleased to report strong operational and financial delivery for Gulf Keystone in 2021. By growing production from the Shaikan Field and maintaining our rigorous focus on cost and capital discipline, we were able to capitalise on our leverage to an improving oil price and generate revenue of $301 million and adjusted EBITDA of $223 million. We delivered on our strategy of balancing investment in sustainable growth and shareholder returns, as we resumed drilling activities and submitted a draft Field Development Plan to the Ministry of Natural Resources while also returning $100 million of dividends to our shareholders.

The foundation of our performance is a rigorous focus on safety, which is one of Gulf Keystone's core values. Despite carefully managing the resumption of drilling activities, we were disappointed to record an LTI in October. We are committed to continuous learning and carried out detailed investigations and implemented remedial actions to safeguard against future incidents.

Gross average production in 2021 was 43,440 bopd, at the top end of our tightened guidance range of 42,000-44,000 bopd. This represented a 19% increase versus the prior year and the third consecutive year of production growth. Higher production was driven by the contribution from well workovers taking place in 2020 and 2021 and the contribution of two new wells, SH-13 and SH-14, at the end of the year.

We were pleased to successfully restart drilling activities in June ahead of schedule. Despite a promising start, the need for an acid stimulation programme on SH-13 and equipment failures and wellbore issues in the subsequent side-track on SH-14 created delays. Nonetheless, we were able to surmount these challenges to bring SH-13 and SH-14 onstream towards the end of the year and spud SH-15 in early 2022.

We also continued to progress development of the full potential of the Shaikan Field's significant reserves and resources with the submission of a draft Field Development Plan to the Ministry of Natural Resources towards the end of 2021. This was the result of several months of constructive engagement with the MNR and our partner MOL following the resumption of discussions in 2021.

The draft FDP comprises a plan to increase Phase 1 gross production plateau to between 85,000-95,000 bopd while significantly reducing our carbon intensity. We plan to achieve this by expanding Jurassic gross production plateau up to 85,000 bopd and testing the Triassic reservoir, targeting gross production plateau of up to 10,000 bopd. At the same time, we will implement a Gas Management Plan to eliminate routine flaring through the reinjection of natural gas into the reservoir, underpinning our target to more than halve our scope 1 and 2 emissions per barrel by 2025. The Gas Management Plan is critical to our licence to operate in Kurdistan and responds to both GKP's and the KRG's desire to eliminate routine flaring and reduce the emissions intensity of the region's production.

In keeping with our commitment to eliminate routine flaring, we have applied to endorse the World Bank's "Zero Routine Flaring by 2030" initiative. Beyond the Gas Management Plan, we are exploring the viability of several other projects to reduce our scope 1 and 2 emissions intensity further beyond the 2025 target.

Our focus on climate risk is just one part of our ESG agenda and sustainability strategy. Our other priorities include working safely, minimising our impact on the local environment, supporting and developing our people, generating economic value in Kurdistan and maintaining strong governance and compliance. We are particularly proud of our social and economic contribution to Kurdistan, our home for over 15 years, and see significant opportunities from the FDP for further local job creation, workforce development and investment in our local supply chain and communities as we generate increasing revenues for the KRG and the region from the Shaikan Field. In 2021, $356 million was generated for the KRG, primarily from production entitlements, royalties and capacity building payments.

While we continued to invest in growth in 2021, we also delivered against our strategic commitment to balance growth with shareholder returns. We understand the importance of cash returns to our shareholders and we were pleased to reinstate our dividend policy of distributing at least $25 million annually, subsequently distributing total dividends in the year of $100 million. Since the beginning of 2022, we have distributed a further $50 million and we are delighted to declare $90million of additional dividends comprising a $25 million 2021 ordinary annual dividend for shareholder approval at the Company's AGM on 24 June 2022 and a $65 million interim dividend payable in May 2022.

We have entered 2022 with momentum and hit the milestone in February of 100 MMstb cumulative gross production from the Field since inception. Gross average production year to date has been around c.45,500 bopd, and we remain focused on delivering our 2022 gross average production guidance of 44,000-50,000 bopd.

As a Company, we are deeply saddened and concerned about the invasion of Ukraine and the resulting humanitarian crisis. Our thoughts are with the people of Ukraine and we are all hoping for a swift and peaceful end to the conflict.

While there has been no impact on our operations to date, we are closely monitoring the developing situation in Ukraine. This includes potential sanctions being imposed on Russian entities, which could adversely impact our business.

We also continue to monitor the broader political and regulatory environment in the Kurdistan Region and Federal Iraq following the recent ruling by the Iraqi Federal Supreme Court regarding the Kurdistan Region Oil & Gas Law. We have noted the KRG’s strong opposition to the ruling and agreement by both the KRG and the Federal Government to engage on what has been a longstanding issue. To date, we have seen no impact from the ruling on our business.

While the timing of approval of the FDP is uncertain given the scale of the project, constructive engagement continues with the MNR, and further progress is required before we fully execute FDP activity including drilling beyond SH-15. For the remainder of 2022, we are focused on executing activity that enables us to expedite the FDP following approval. This includes activities to prepare for expansion of our production facilities to include water handling and preparation of well pads and installation of flowlines to enable a continuous drilling programme. We are also focused on well interventions and workovers. Net capital expenditure guidance for 2022 is $85-$95 million.

We are targeting gross Opex of $2.9-$3.3/bbl, with the increase versus 2021 primarily due to increased operational activity and the continued catch up of previously scheduled work programmes deferred due to COVID-19.

Assuming timely payment of invoices and continuing strong oil prices, we are expecting strong cash flow generation in 2022. This would provide flexibility to fund a potential increase in capital expenditure, with progress on the FDP, and the opportunity for further distributions to shareholders, while preserving adequate liquidity and maintaining a robust balance sheet.

I would like to thank the teams in Kurdistan and the UK for their hard work and contributions to a strong year of performance. I would also like to give my thanks to our Chief Operating Officer, Stuart Catterall, who has retired from Gulf Keystone after five years with the Company. Stuart has helped us steer the Company through a volatile oil price cycle and the COVID-19 pandemic, enabling us to emerge stronger and more focused on driving sustainable value from the Shaikan Field.

Stuart will be succeeded by John Hulme who joins us end April from Noreco where he was their COO. John brings a wealth of experience from more than 30 years in the industry, previously working at Exxon, Anadarko, Santos and Newfield. I look forward to welcoming John to GKP.

Jon Harris
Chief Executive Officer

Operational review

Gulf Keystone's operational performance was solid in 2021, with a continued increase in production, the successful resumption of drilling activities and the submission of a draft Field Development Plan to the MNR.

As ever, a rigorous focus on safety underpinned all our activity. As drilling restarted, we took extra precautions to ensure all drilling and operational staff on site were prepared. Unfortunately, we were disappointed to incur one LTI during drilling operations after over 660 LTI-free days.

Following a challenging year in 2020 from the COVID-19 pandemic, the rollout of vaccinations in 2021 facilitated a gradual improvement in operating conditions. We were pleased to see 97% of our staff get double vaccinated in the year following a successful awareness campaign. This enabled us to ease health protocols on site, including a move from three shifts back to two, although access to our offices in Erbil and London remained restricted with employees encouraged to work from home.

We achieved gross average production of 43,440 bopd in 2021, towards the upper end of our tightened guidance range of 42,000-44,000 bopd and a 19% increase versus 2020. Higher production was driven by a full year of production from SH-9, the successful workover of SH-12 towards the end of 2020 and enhanced production from the installation in 2021 of a multiphase pump on SH-5 and a jet pump in SH-10. We also completed two new wells, SH-13 and SH-14, towards the end of 2021. Both plant and pipeline uptime remained high at above 99%.

Following an extended hiatus in 2020 due to the COVID-19 pandemic, we successfully restarted drilling activities in June 2021 ahead of schedule. Rapid mobilisation was made possible by a cohesive effort across the whole organisation and our excellent relationships with our suppliers. Despite the early completion of SH-13, progress subsequently slowed as an acid stimulation programme was required on the well to access the broader fracture network. During the drilling of SH-14, equipment failures and wellbore issues in the subsequent side-track led to delays, in turn resulting in a deferral of spudding SH-15 to January 2022. Nonetheless, despite these issues, SH-13 and SH-14 were brought on stream towards the end of the year. We also completed the debottlenecking of PF-2, increasing total field capacity to c.57,500 bopd.

Draft Shaikan Field Development Plan

With the submission of the draft Field Development Plan to the MNR in November 2021, we took an important step towards unlocking the full potential of the Shaikan Field. Constructive discussions continue with the MNR and, while final timing of approval remains uncertain due to the complexity of the project, we are pleased to provide an interim update on the progress that we have made to date on Phase 1 of the draft FDP. Final details and cost estimates may vary and we expect to provide an update upon FDP approval.

As a result of a series of optimisations, we are now targeting to increase Phase 1 gross plateau production to between 85,000-95,000 bopd, including up to 85,000 bopd from the Jurassic reservoir and up to 10,000 bopd from the Triassic reservoir.

In addition, we have updated the Gas Management Plan from processing and export of gas with recovery of elemental sulphur, to reinjection of gas into the reservoir, underpinning our target to eliminate routine flaring and more than halve our scope 1 and 2 emissions per barrel by 2025. The project is expected to be executed in parallel with the Phase 1 increase in oil production.

From FDP approval, the expected duration of the Phase 1 Jurassic and Triassic projects is 36 to 42 months and the Gas Management Plan is 18 to 24 months. Total Phase 1 gross Capex is currently estimated to be $800-$925 million, up around $160 million from the previous FDP with the objective of increasing production towards 95,000 bopd through project optimisations. We continue to review opportunities to further optimise the project.

While the focus remains on delivering Phase 1 of the FDP, we are committed to exploiting the further potential of the field with a vision of increasing production beyond 85,000-95,000 bopd through the expansion of the Triassic reservoir and a Cretaceous reservoir pilot.

Current operational activity and 2022 outlook

Gross average production since the beginning of the year has been around c.45,500 bopd. After acid stimulations, current SH-13 production is in line with expectations, while we continue to explore options to further increase SH-14 production. Following the early appearance of trace quantities of water, SH-12 is currently shut-in while we investigate near-term production options ahead of the installation of planned water handling facilities.

Looking ahead to the rest of the year, we remain focused on delivering gross average production of 44,000-50,000 bopd, reflecting the anticipated production contribution from SH-15, which is currently being hooked up ahead of targeted start-up in Q2 2022, and the benefits of an intervention and workover campaign with our existing wells with the primary focus of production assurance and enhancement, where possible..

We remain confident in Shaikan Field gross 2P reserves of 489 MMstb and gross 2C resources of 293 MMstb, based on the 31 December 2020 Competent Person's Report adjusted for 2021 production from 2P reserves of around 16 MMstb.

Constructive engagement continues with the MNR on the FDP, and further progress is required before we fully execute FDP activity including drilling beyond SH-15. In 2022, we are focused on executing activity that enables us to expedite the FDP following approval. This includes activities to prepare for expansion of our production facilities to include water handling and a continuous drilling programme. Net capital expenditure guidance for 2022 is $85-$95 million.

Sustainability

We continue to work hard on enhancing the sustainability of our business, with Board approval of our sustainability strategy and roadmap in 2021. We remain focused on a number of core priorities. First, we continue to target zero harm across our operations, particularly as operational activity continues to increase. Second, the Gas Management Plan will enable us to reduce our carbon intensity by more than 50% by 2025 and we are also exploring the viability of other projects that could enable us to reduce our scope 1 and 2 emissions further. Third, we continue to develop our people and identify opportunities to enhance diversity and inclusion across our business. Lastly, we remain intensely focused on amplifying the broader social and economic value of the Shaikan Field and our operations for Kurdistan. We look forward to updating you on our progress.

Jon Harris
Chief Executive Officer

Financial review

Key financial highlights

		Year ended 31 December 2021	Year ended 31 December 2020
Gross average production[(1)]	bopd	**43,440**	36,625
Dated Brent[(1)]	$/bbl	**70.8**	42.0
Realised price[(1)]	$/bbl	**49.7**	20.9
Revenue	$m	**301.4**	108.4
Operating costs	$m	**34.4**	27.4
Gross operating costs per barrel[(1)]	$/bbl	**2.7**	2.6
Other general and administrative expenses	$m	**13.6**	12.3
Incurred in relation to Shaikan Field	$m	**4.1**	5.0
Corporate G&A	$m	**9.5**	7.3
Share option expense	$m	**8.5**	1.2
Adjusted EBITDA[(1)]	$m	**222.7**	56.7
Profit/(loss) after tax	$m	**164.6**	(47.3)
Basic earnings/(loss) per share	cents	**77.14**	(22.45)
Revenue and arrears receipts[(1)]	$m	**221.7**	101.1
Net capital expenditure[(1)]	$m	**50.8**	45.9
Free cash flow[(1)]	$m	**122.2**	(22.9)
Dividends	$m	**100.0**	-
Cash and cash equivalents	$m	**169.9**	147.8
Face amount of the Notes	$m	**100.0**	100.0
Net cash[(1)]	$m	**69.9**	47.8

(1) Gross average production, dated Brent, realised price, gross operating costs per barrel, Adjusted EBITDA, revenue and arrears receipts being actual cash received during the year, net capital expenditure, free cash flow and net cash are either non-financial or non-IFRS measures and, where necessary, are explained in the summary of non-IFRS measures.

Strategically, Gulf Keystone is committed to a disciplined approach to capital allocation and cost control, and maintaining a prudent level of liquidity and robust financial position. By taking decisive action in 2020 to reduce capital expenditures, operating costs and general & administrative expenses, the Company entered 2021 with a strong balance sheet and well positioned to capitalise on improving macroeconomic fundamentals. In 2021, the Company restarted its development programme, generated a significant increase in adjusted EBITDA and paid dividends of $100 million, while further strengthening the balance sheet.

Adjusted EBITDA

Adjusted EBITDA grew almost four-fold in 2021 to $222.7 million (2020: $56.7 million), driven by a strong increase in the oil price and higher production, partly offset by higher operating costs, share option expense and capacity building payments.

Gross average production was 43,440 bopd in 2021, up 19% from 36,625 bopd in 2020 and towards the upper end of the Company's tightened 2021 guidance range of 42,000-44,000 bopd. With Gulf Keystone's leverage to the strengthening of the Dated Brent price from an average of $42.0/bbl in 2020 to $70.8/bbl in 2021, the realised price per barrel more than doubled to $49.7/bbl, resulting in an almost tripling in revenue from $108.4 million in 2020 to $301.4 million in 2021. Revenue was partially offset by a corresponding $15.2 million increase in capacity building payments to $23.5 million (2020: $8.4 million), which is a component of the KRG's entitlement from the Shaikan Field.

Gulf Keystone continues to maintain strict control over its cost base. Gross operating costs per barrel increased 4% to $2.7/bbl in 2021 (2020: $2.6/bbl), in the middle of the Company's 2021 guidance range of $2.5-$2.9/bbl. The increase in operating costs in 2021 to $34.4 million (2020: $27.4 million), primarily due to increased production, maintenance and well services activity that were deferred from 2020, was substantially offset by higher production.

Other general and administrative expenses (G&A), comprising Shaikan Field and corporate support costs, were slightly higher in 2021 at $13.6 million (2020: $12.3 million), reflecting increasing activity levels. Share option expense in the period increased by $7.3 million, principally due to tax settlements related to the exercise of former Directors' contractual Value Creation Plan share option entitlements being made in cash and an increase in accrued national insurance contributions resulting from the increased share price.

Cash flows

Cash increased in 2021 from $147.8 million to $169.9 million. The Group has notes outstanding with a principal balance of $100.0 million (2020: $100.0 million) that do not mature until July 2023, resulting in net cash of $69.9 million at 31 December 2021. The cash balance has consistently exceeded the $100.0 million notes outstanding since issue in 2018 and the Company continues to retain significant covenant headroom.

The Company generated cash from operating activities of $178.6 million in 2021, up from $42.6 million in 2020 due principally to the increase in Adjusted EBITDA.

In 2021, the Company received revenue receipts of $221.7 million from the KRG for crude oil sales related to the December 2020 to August 2021 invoices and partial repayment of arrears related to the outstanding November 2019 to February 2020 invoices. Of the original outstanding arrears of $73.3 million net to GKP, a total of $32.4 million was repaid in 2021, based on an arrangement with the KRG and IOCs operating in Kurdistan(1). Despite continued collection of arrears, the delays to payments from the KRG have contributed to a working capital increase of $38.5 million (2020: $9.0 million increase).

Since the beginning of 2022, the Company has received a further $106.4 million net to GKP for crude oil sales and arrears related to the September 2021 to November 2021 invoices. As at 29 March 2022, the outstanding arrears balance was $21.9 million net to GKP.

With the improvement in oil prices and continuous payments from the KRG, Gulf Keystone restarted its investment programme in the Shaikan Field and resumed drilling activities in June. During the year, the Company invested net capital expenditure of $50.8 million (2020: $45.9 million), primarily on the completion of the SH-13 and SH-14 wells, related civil and flowline works and the debottlenecking of PF-2. Net capital expenditure was slightly lower than final 2021 guidance of approximately $55 million.

As at 31 December 2021, there were $401 million gross of unrecovered costs, subject to potential cost audit by the KRG. The R-factor, calculated as cumulative gross revenue receipts of $1,478 million divided by cumulative gross costs of $1,543 million, was 0.96. The unrecovered cost pool and R-factor are used to calculate monthly cost oil and profit oil entitlements, respectively, owed to the Company from crude oil sales.

Free cash flow generation was $122.2 million in 2021, an increase of $145.1 million versus the prior year (2020: ($22.9) million), enabling the Company to continue to deliver against its commitment of balancing investment in growth with returns to shareholders. In March 2021, Gulf Keystone reinstated its dividend policy of paying at least $25 million annually. Given continuing strong oil prices and cash generation in the year, the Company paid total dividends of $100 million. Since the beginning of 2022, Gulf Keystone has paid an additional dividend of $50 million to shareholders.

The Group performed a cash flow and liquidity analysis based on which the Directors have a reasonable expectation that the Group has adequate resources to continue to operate for the foreseeable future. Therefore, the going concern basis of accounting is used to prepare the financial statements.

Outlook

The Company has a strong balance sheet with cash and cash equivalents of $182.7 million at 29 March 2022.

Looking ahead to 2022, we are currently planning to invest net capital expenditure of $85-95 million. This includes the drilling of SH-15, well interventions and workovers and activity that enables us to expedite the FDP following approval, including preparatory work for the continued expansion of our production facilities to include water handling and for a continuous drilling programme. Constructive engagement continues with the MNR on the FDP, and further progress is required before we fully execute FDP activity including drilling beyond SH-15. With progress on the FDP, we expect to resume drilling and increase 2022 capital guidance.

We are targeting gross Opex of $2.9-$3.3/bbl, driven by increased operational activity and the continued catch up of previously scheduled work programmes deferred due to COVID-19. 2022 annual gross average production is expected to be 44,000-50,000 bopd.

Given the strong oil price outlook and our flexible spending programme, we currently have no hedging programme in place. We consider hedging on an ongoing basis, taking into account macro-economic and corporate considerations.

In line with our commitment to balancing investment in growth with returns to shareholders, we are pleased to declare $90 million of dividends, comprising a $25 million 2021 ordinary annual dividend for shareholder approval at the Company's AGM on 24 June 2022 and a $65 million interim dividend payable in May 2022.

Assuming timely payment of invoices and continuing strong oil prices, we are expecting strong cash flow generation in 2022. This would provide flexibility to fund a potential increase in capital expenditure, with progress on the FDP, and the opportunity for further distributions to shareholders, while preserving adequate liquidity and maintaining a robust balance sheet

Ian Weatherdon
Chief Financial Officer

(1) The repayment of arrears related to January 2021 and February 2021 were calculated based on 50% of the difference between average monthly dated Brent price and $50/bbl multiplied by the gross Shaikan crude sold in a month. The KRG advised IOCs that since the dated Brent price had remained consistently well above $50/bbl, the 50% difference would be changed to 20% from March 2021 and onwards.

Non-IFRS measures

The Group uses certain measures to assess the financial performance of its business. Some of these measures are termed "non-IFRS measures" because they exclude amounts that are included in, or include amounts that are excluded from, the most directly comparable measure calculated and presented in accordance with IFRS, or are calculated using financial measures that are not calculated in accordance with IFRS. These non-IFRS measures include financial measures such as operating costs and non-financial measures such as gross average production.

The Group uses such measures to measure and monitor operating performance and liquidity, in presentations to the Board and as a basis for strategic planning and forecasting. The directors believe that these and similar measures are used widely by certain investors, securities analysts and other interested parties as supplemental measures of performance and liquidity.

The non-IFRS measures may not be comparable to other similarly titled measures used by other companies and have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of the Group's operating results as reported under IFRS. An explanation of the relevance of each of the non-IFRS measures and a description of how they are calculated is set out below. Additionally, a reconciliation of the non-IFRS measures to the most directly comparable measures calculated and presented in accordance with IFRS and a discussion of their limitations is set out below, where applicable. The Group does not regard these non-IFRS measures as a substitute for, or superior to, the equivalent measures calculated and presented in accordance with IFRS or those calculated using financial measures that are calculated in accordance with IFRS.

Gross operating costs per barrel (unaudited)
Gross operating costs are divided by gross production to arrive at operating costs per bbl.

	2021	2020
Gross production (MMbbls)	**15.9**	13.4
Gross operating costs ($ million)[1]	**43.0**	34.2
Gross operating costs per barrel ($ per bbl)	**2.7**	2.6

[1]Gross operating costs equate to operating costs (see note 3) adjusted for the Group's 80% working interest in the Shaikan Field.

Adjusted EBITDA
Adjusted EBITDA is a useful indicator of the Group's profitability, which excludes the impact of costs attributable to tax (expense)/credit, finance costs, finance revenue, depreciation, amortisation and impairment of receivables.

	2021	2020
	$ million	$ million
Profit/(loss) after tax	**164.6**	(47.3)
Finance costs	**11.4**	14.1
Finance revenue	**(0.4)**	(1.3)
Tax (credit)/expense	**(0.9)**	0.3
Depreciation of oil and gas assets	**54.1**	82.8
Depreciation of other PPE assets and amortisation of intangibles	**1.0**	1.3
Impairment of receivables	**(7.1)**	6.8
Adjusted EBITDA	**222.7**	56.7

Net capital expenditure
Net capital expenditure is the value of the Group's additions to oil and gas assets excluding the change in value of the decommissioning asset and movements in drilling and other equipment.

	2021	2020
		Restated
	$ million	$ million
Additions to oil and gas assets (note 11)	**46.2**	51.7
(Increase)/decrease of drilling and other equipment classified as oil and gas assets	**4.6**	(5.9)
Net capital expenditure	**50.8**	45.8

Net Cash

Net Cash is a useful indicator of the Group's indebtedness and financial flexibility because it indicates the level of cash and cash equivalents less cash borrowings within the Group's business. Net cash is defined as cash and cash equivalents, less current and non-current borrowings and non-cash adjustments. Non-cash adjustments include unamortised arrangement fees and other adjustments.

	2021	2020
		Restated
	$ million	$ million
Outstanding Notes	**(99.1)**	(98.6)
Unamortised issue costs (note 16)	**(0.9)**	(1.4)
Cash and cash equivalents	**169.9**	147.8
Net cash	**69.9**	47.8

Free cash flow

Free cash flow represents the Group's cash flows, before any dividends or share buy-backs.

	2021	2020
		Restated
	$ million	$ million
Net cash generated from operating activities	**178.6**	42.6
Net cash used in investing activities	**(55.7)**	(64.2)
Payment of leases	**(0.7)**	(1.3)
Free cash flow	**122.2**	(22.9)

Consolidated income statement
For the year ended 31 December 2021

	Notes	2021 $'000	2020 $'000
Revenue	2	**301,389**	108,449
Cost of sales	3	**(111,721)**	(121,507)
Decrease/(increase) of impairment provision on trade receivables	14	**7,065**	(6,776)
Gross profit/(loss)		**196,733**	(19,834)
Other general and administrative expenses	4	**(13,643)**	(12,312)
Share option related expenses	5	**(8,490)**	(1,235)
Profit/(loss) from operations		**174,600**	(33,381)
Finance revenue	7	**419**	1,278
Finance costs	7	**(11,353)**	(14,087)
Foreign exchange gains/(losses)		**57**	(841)
Profit/(loss) before tax		**163,723**	(47,031)
Tax credit/(expense)	8	**874**	(311)
Profit/(loss) after tax for the year		**164,597**	(47,342)
Profit/(loss) per share (cents)			
Basic	9	**77.14**	(22.45)
Diluted	9	**73.04**	(22.45)

Consolidated statement of comprehensive income
For the year ended 31 December 2021

	2021 $'000	2020 $'000
Profit/(loss) after tax for the year	**164,597**	(47,342)
Items that may be reclassified to the income statement in subsequent periods:		
Fair value losses arising in the period	**(2,021)**	(1,732)
Cumulative losses arising on hedging instruments reclassified to revenue	**3,753**	-
Exchange differences on translation of foreign operations	**(254)**	707
Total comprehensive income/(expense) for the year	**166,075**	(48,367)

Consolidated balance sheet

	Notes	**31 December 2021** **$'000**	31 December 2020 Restated[1] $'000	1 January 2020 Restated[1] $'000
Non-current assets				
Intangible assets	10	**3,583**	933	454
Property, plant and equipment	11	**404,205**	405,469[1]	432,507[1]
Trade receivables	14	**-**	59,096	-
Deferred tax asset	18	**1,385**	617	849
		409,173	466,115	433,810
Current assets				
Inventories	13	**6,018**	5,760[1]	6,135[1]
Trade and other receivables	14	**179,200**	37,832	103,181
Derivative financial instruments	19	**-**	977	-
Cash and cash equivalents		**169,866**	147,826	190,762
		355,084	192,395	300,078
Total assets		**764,257**	658,510	733,888
Current liabilities				
Trade and other payables	15	**(98,800)**	(69,123)	(83,981)
Non-current liabilities				
Trade and other payables	15	**(789)**	(1,058)	(1,989)
Borrowings	16	**(99,123)**	(98,633)	(98,192)
Provisions	17	**(43,841)**	(35,671)	(29,807)
		(143,753)	(135,362)	(129,988)
Total liabilities		**(242,553)**	(204,485)	(213,969)
Net assets		**521,704**	454,025	519,919
Equity				
Share capital	20	**213,731**	211,371	229,430
Share premium	20	**742,914**	842,914	871,675
Treasury shares	20	**-**	(2,592)	(29,749)
Cost of hedging reserve		**-**	(1,732)	-
Exchange translation reserve		**(2,768)**	(2,514)	(3,221)
Accumulated losses		**(432,173)**	(593,422)	(548,216)
Total equity		**521,704**	454,025	519,919

[1]The comparative consolidated balance sheet has been restated to reflect a reclassification of inventory items that are to be used in the development of the Shaikan field to property, plant and equipment. See note 28 for details regarding the restatement.

The financial statements were approved by the Board of Directors and authorised for issue on 29 March 2022 and signed on its behalf by:

Jon Harris
Chief Executive Officer

Ian Weatherdon
Chief Financial Officer

Consolidated statement of changes in equity
For the year ended 31 December 2021

	Notes	Attributable to equity holders of the Company						
		Share capital $'000	Share premium $'000	Treasury shares $'000	Cost of hedging reserve $'000	Exchange translation reserve $'000	Accumulated losses $'000	Total equity $'000
Balance at 1 January 2020		**229,430**	**871,675**	**(29,749)**	**-**	**(3,221)**	**(548,216)**	**519,919**
Net loss for the year		-	-	-	-	-	(47,342)	(47,342)
Cash flow hedge – fair value movements		-	-	-	(1,732)	-	-	(1,732)
Exchange difference on translation of foreign operations		-	-	-	-	707	-	707
Total comprehensive (expense)/income for the year		**-**	**-**	**-**	**(1,732)**	**707**	**(47,342)**	**(48,367)**
Employee share schemes	24	-	-	-	-	-	2,637	2,637
Share buy-back	20	-	-	(20,164)	-	-	-	(20,164)
Share options exercised		-	-	501	-	-	(501)	-
Share cancellation	20	(18,059)	(28,761)	46,820	-	-	-	-
Balance at 31 December 2020		**211,371**	**842,914**	**(2,592)**	**(1,732)**	**(2,514)**	**(593,422)**	**454,025**
Net profit for the year		-	-	-	-	-	164,597	164,597
Cash flow hedge – fair value movements		-	-	-	1,732	-	-	1,732
Exchange difference on translation of foreign operations		-	-	-	-	(254)	-	(254)
Total comprehensive income/(expense) for the year		**-**	**-**	**-**	**1,732**	**(254)**	**164,597**	**166,075**
Dividends paid	25	-	(100,000)	-	-	-	-	(100,000)
Employee share schemes	24	-	-	-	-	-	1,604	1,604
Share options exercised		-	-	2,592	-	-	(2,592)	-
Share issues	20	2,360	-	-	-	-	(2,360)	-
Balance at 31 December 2021		**213,731**	**742,914**	**-**	**-**	**(2,768)**	**(432,173)**	**521,704**

Consolidated cash flow statement
For the year ended 31 December 2021

	Notes	2021 $'000	2020 Restated $'000
Operating activities			
Cash generated from operations	21	**189,155**	56,734
Interest received	7	**419**	1,278
Interest paid	7	**(10,000)**	(10,000)
Payment of put option premium		**(1,043)**	(5,371)
Net cash generated from operating activities		**178,531**	42,641
Investing activities			
Purchase of intangible assets		**(2,725)**	(458)
Purchase of property, plant and equipment	21	**(52,959)**	(63,760)
Net cash used in investing activities		**(55,684)**	(64,218)
Financing activities			
Payment of dividends	25	**(100,000)**	-
Share buy-back		**-**	(20,164)
Payment of leases		**(688)**	(1,317)
Net cash used in financing activities		**(100,688)**	(21,481)
Net increase/(decrease) in cash and cash equivalents		**22,159**	(43,058)
Cash and cash equivalents at beginning of year		**147,826**	190,762
Effect of foreign exchange rate changes		**(119)**	122
Cash and cash equivalents at end of the year being bank balances and cash on hand		**169,866**	147,826

Summary of significant accounting policies

General information
The Company is incorporated in Bermuda (registered address: Cedar House, 3rd Floor, 41 Cedar Avenue, Hamilton, HM12, Bermuda). On 25 March 2014, the Company's common shares were admitted, with a standard listing, to the Official List of the United Kingdom Listing Authority ("UKLA") and to trading on the London Stock Exchange's Main Market for listed securities. Previously, the Company was quoted on Alternative Investment Market, a market operated by the London Stock Exchange. In 2008, the Company established a Level 1 American Depositary Receipt programme in conjunction with the Bank of New York Mellon, which has been appointed as the depositary bank. The Company serves as the holding company for the Group, which is engaged in oil and gas exploration, development and production, operating in the Kurdistan Region of Iraq.

The financial information set out in this Results Announcement does not constitute the Company's annual report and accounts for the years ended 31 December 2021 or 2020 but is derived from those accounts. The auditors have reported on those accounts; their reports were unqualified and did not draw attention to any matters by way of emphasis without qualifying their report.

Amendments to International Financial Reporting Standards ("IFRS") that are mandatorily effective for the current year
In the current year, the Group has applied a number of amendments to IFRSs issued by the International Accounting Standards Board (IASB) that are mandatorily effective for an accounting period that begins on or after 1 January 2021.

The following new accounting standards, amendments to existing standards and interpretations are effective on 1 January 2021: Amendments to IFRS 4 Insurance Contracts – deferral of IFRS19, Amendments to IFRS 9, IAS 39, IFRS 7, IFRS 4 and IFRS 16 Interest Rate Benchmark Reform – Phase 2, Amendments to IFRS 16 Leases: Covid-19-related rent concessions beyond 30 June 2021. These standards do not and are not expected to have a material impact on the Company's results or financials statement disclosures in the current or future reporting periods.

New and revised IFRSs issued but not yet effective

At the date of approval of these financial statements, the Group has not applied the following new and revised IFRSs that have been issued but are not yet effective by United Kingdom adopted International Accounting Standards:

IFRS 17	*Insurance Contracts*
IFRS 10 and IAS 28 (amendments)	*Sale or Contribution of Assets between an Investor and its Associate or Joint Venture*
Amendments to IAS 1	*Classification of Liabilities as Current or Non-current*
Amendments to IFRS 3	*Reference to the Conceptual Framework*
Amendments to IAS 16	*Property, Plant and Equipment—Proceeds before Intended Use*
Amendments to IAS 37	*Onerous Contracts – Cost of Fulfilling a Contract*
Annual Improvements Standards 2018-20	*Amendments to IFRS 1 first time adoption of IFRS, IFRS 9 financial instruments IFRS 16 Leases and IAS 41 Agriculture.*
Amendments to IAS 1 and IFRS Practice Statement 2	*Disclosure of Accounting Policies*
Amendments to IAS 8	*Definition of Accounting Estimates*
Amendments to IAS 12	*Deferred Tax related to Assets and Liabilities arising from a Single Transaction*

The directors do not expect that the adoption of the Standards listed above will have a material impact on the financial statements of the Group in future periods.

Statement of compliance
The financial statements have been prepared in accordance with United Kingdom adopted International Accounting Standards.

Basis of accounting
The financial statements have been prepared under the historical cost basis, except for the valuation of hydrocarbon inventory and the valuation of certain financial instruments, which have been measured at fair value, and on the going concern basis. Equity-settled share-based payments are recognised at fair value at the date of grant, but are not subsequently revalued. The principal accounting policies adopted are set out below.

Going concern
The Group's business activities, together with the factors likely to affect its future development, performance and position are set out in the Chairman's Statement, the Chief Executive Officer's Review, the Operational Review and the Management of Principal Risks and Uncertainties. The financial position of the Group at the year end and its cash flows and liquidity position are included in the Financial Review.

As at 29 March 2022, the Group had $182.7 million of cash. The Group continues to closely monitor and manage its liquidity. Cash forecasts are regularly produced and sensitivities run for different scenarios including, but not limited to change in commodity prices, different production rates from the Shaikan block, cost contingencies, disruptions to revenue receipts, impact of climate change and geopolitical risks on the Group's operations, etc. In the current year, these have included both the Iraqi Supreme Court ruling on 15 February 2022 and export route availability as a result of the evolving sanctions situation due to the Russian invasion of Ukraine as further described in note 29. The Group's forecasts, taking into account the applicable risks, stress test scenarios and potential mitigating actions, show that it has sufficient financial resources for the 12 months from the date of approval of the 2021 Annual Report and Accounts.

Based on the analysis performed, the directors have a reasonable expectation that the Group has adequate resources to continue to operate for the foreseeable future. Thus, the going concern basis of accounting is used to prepare the annual consolidated financial statements.

Basis of consolidation
The consolidated financial statements incorporate the financial statements of the Company and enterprises controlled by the Company (its subsidiaries) made up to 31 December each year. Control is achieved where the Company has the power to govern the financial and operating policies of an investee entity, so as to obtain benefits from its activities.

Joint arrangements
The Group is engaged in oil and gas exploration, development and production through unincorporated joint arrangements; these are classified as joint operations in accordance with IFRS 11. The Group accounts for its share of the results and net assets of these joint operations. Where the Group acts as Operator of the joint operation, the gross liabilities and receivables (including amounts due to or from non-operating partners) of the joint operation are included in the Group's balance sheet.

Sales revenue
The recognition of revenue, particularly the recognition of revenue from export sales of crude oil, is considered to be a key accounting judgement.

All oil is sold by the Shaikan Contractor (the Company and Kalegran BV, a subsidiary of MOL Hungarian Oil & Gas Plc, ("MOL")) to the Kurdistan Regional Government ("KRG"), who in turn resell the oil. The selling price is determined in accordance with the principles of the crude oil export sales agreement ("Crude Oil Sales Agreement"), based on the average monthly dated Brent crude price less a quality discount and a pipeline tariff. The sales agreement also specifies the delivery point and the payment terms relating to export sales of crude oil. The Crude Oil Sales Agreement has been governing Shaikan crude oil sales from 1 October 2017 onwards.

As the payment mechanism for sales is developing within the Kurdistan Region of Iraq, the Group currently considers that revenue can best be reliably measured when the cash receipt is assured. The assessment of whether cash receipt is assured is based on management's evaluation of the reliability of the KRG's payments to the international oil companies operating in the Kurdistan Region of Iraq.

The value of sales revenue is determined after taking account of the following:

- All crude oil sales were made via the Kurdistan Export Pipeline. The point of sale is the point that the crude oil is injected into the Kurdistan Export Pipeline; and
- GKP recognises revenue for its share of the revenue on a cash-assured basis and these amounts of recognised revenue may be lower than the Company's entitlement under the Shaikan PSC, giving rise to unrecognised revenue amounts.

During past PSC negotiations with the Ministry of Natural Resources ("MNR"), it was tentatively agreed that the Shaikan Contractor would provide the KRG a 20% carried working interest in the PSC. This would result in a reduction of GKP's working interest from 80% to 61.5%. To compensate for such decrease, capacity building payments expense would be reduced from 40% to 20% of profit petroleum. While the PSC has not been formally amended, it was agreed that GKP would invoice the KRG for oil sales based on the proposed revised terms from October 2017. Since revenue is recognised on a cash assured basis, the financial statements reflect the proposed revised working interest of 61.5%. Relative to the PSC terms, the proposed revised invoicing terms result in a decrease in both revenue and cost of sales and on a net basis are slightly positive for the Company.

As part of earlier PSC negotiations, on 16 March 2016, GKP signed a bilateral agreement with the MNR (the "Bilateral Agreement"). The Bilateral Agreement included a reduction in the Group's capacity building payment from 40% to 30% of profit petroleum. Subsequent to signing the Bilateral Agreement, further negotiations resulted in the capacity building payment rate being reduced from 30% to 20%, which has formed the basis for all oil sales invoices to date as noted above. Since PSC negotiations have not been finalised, GKP has included a non-cash payable for the difference between the capacity building rate of 20% and 30%, which is recognised in cost of sales and other payables.

The Company is in constructive dialogue with the MNR to confirm whether to proceed with a formal amendment to the PSC to reflect current invoice terms or to revert to the original PSC terms.

Income tax arising from the Company's activities under its PSC is settled by the KRG on behalf of the Company. However, the Company is not able to measure the amount of income tax that has been paid on its behalf and, therefore, the notional income tax amounts have not been included in revenue or in the tax charge.

Finance revenue
Interest revenue is accrued on a time basis, by reference to the principal outstanding and at the effective rate of interest applicable, which is the rate that exactly discounts estimated future cash receipts through the expected life of the financial asset to that asset's net carrying amount on initial recognition.

Intangible assets
Intangible assets include computer software and are measured at cost and amortised over their expected useful economic lives of three years.

Property, plant and equipment ("PPE")

Oil and gas assets
Development and production assets
Development and production assets are accumulated on a field-by-field basis and represent the costs of acquisition and developing the commercial reserves discovered and bringing them into production, together with the exploration and evaluation expenditure incurred in finding commercial reserves, directly attributable overheads and costs for future restoration and decommissioning. These costs are capitalised as part of PPE and depreciated based on the Group's depreciation of oil and gas assets policy.

The net book values of producing assets are depreciated generally on a field-by-field basis using the unit of production ("UOP") basis which uses the ratio of oil and gas production in the period to the remaining commercial reserves plus the production in the period. Production associated with unrecognised export sales revenue is included in the depreciation, depletion and amortisation ("DD&A") calculation. Costs used in the calculation comprise the net book value of the field, and any anticipated costs to develop such reserves.

Commercial reserves are proven and probable ("2P") reserves together with, where considered appropriate, a risked portion of 2C contingent resources, which are estimated using standard recognised evaluation techniques.

The reserves estimate used in 2021 is based on values as at 31 December 2020 included in the Competent Persons Reports ("CPR") prepared by ERC Equipoise.

Other property, plant and equipment
Other property, plant and equipment are principally equipment used in the field which are separately identifiable to development and production assets, and typically have a shorter useful economic life. Assets are carried at cost, less any accumulated depreciation and accumulated impairment losses. Costs include purchase price, construction and installation costs.

These assets are expensed on a straight-line basis over their estimated useful lives of 3 years from the date they are put in use.

Fixtures and equipment
Fixtures and equipment assets are stated at cost less accumulated depreciation and any accumulated impairment losses. These assets are expensed on a straight-line basis over their estimated useful lives of 5 years from the date they are available for use.

Impairment of PPE and intangible non-current assets
At each balance sheet date, the Group reviews the carrying amounts of its tangible and intangible assets 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, or group of assets, is estimated in order to determine the extent of the impairment loss (if any).

For assets which do not generate cash flows that are independent from other assets, the Group estimates the recoverable amount of the cash-generating unit to which the asset belongs.

Recoverable amount is the higher of fair value less costs to sell and value in use. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which the estimates of future cash flows have not been adjusted.

Any impairment identified is immediately recognised as an expense.

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

Investment income earned on the temporary investment of specific borrowings pending their expenditure on qualifying assets is deducted from the borrowing costs eligible for capitalisation.

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

Taxation
Tax expense or credit represents the sum of tax currently payable or recoverable and deferred tax.

Tax currently payable or recoverable is based on taxable profit or loss for the year. Current tax assets and liabilities are measured at the amount expected to be recovered from or paid to the taxation authorities, based on tax rates and laws that are enacted or substantively enacted by the balance sheet date.

As described in the revenue accounting policy section above, it is not possible to calculate the amount of notional tax in relation to any tax liabilities settled on behalf of the Group by the KRG.

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 and is accounted for using the balance sheet liability method. Deferred tax liabilities are generally recognised for all taxable temporary differences and deferred tax assets are recognised to the extent that it is probable that taxable profits will be available against which deductible temporary differences can be utilised. Such assets and liabilities are not recognised if the temporary difference arises from the initial recognition of goodwill or from the initial recognition of other assets and liabilities in a transaction that affects neither the taxable profit nor the accounting profit.

The carrying amount of deferred tax assets is reviewed at each balance sheet date and reduced to the extent that it is no longer probable that sufficient taxable profits will be available to allow all or part assets 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 based on tax laws and rates that have been enacted or substantively enacted by the balance sheet date. Deferred tax is charged or credited in the income statement, except when it relates to items charged or credited directly to equity, in which case the deferred tax is also recognised in equity.

Foreign currencies
The individual financial statements of each company are presented in the currency of the primary economic environment in which it operates (its functional currency). For the purpose of the consolidated financial statements, the results and the financial position of the Group are expressed in US dollars, which is the presentation currency for the consolidated financial statements.

In preparing the financial statements of the individual companies, transactions in currencies other than the entity's functional currency are recorded at the rates of exchange prevailing on the dates of the transactions. At each balance sheet date, monetary assets and liabilities that are denominated in foreign currencies are retranslated at the rates prevailing on the balance sheet date. Non-monetary assets and liabilities carried at fair value that are denominated in foreign currencies are translated at the rates prevailing at the date when the fair value was determined. Gains and losses arising on retranslation are included in the income statement for the year.

On consolidation, the assets and liabilities of the Group's foreign operations which use functional currencies other than US dollars are translated at exchange rates prevailing on the balance sheet date. Income and expense items are translated at the average exchange rates for the period. Exchange differences arising, if any, are recognised in other comprehensive income and accumulated in equity in the Group's translation reserve. On the disposal of a foreign operation, such translation differences are reclassified to profit or loss.

Inventories

Inventories, except for hydrocarbon inventories, are stated at the lower of cost and net realisable value. Cost comprises direct materials and, where applicable, direct labour costs and those overheads that have been incurred in bringing the inventories to their present location and condition. Cost is calculated using the weighted average cost method. Hydrocarbon inventories are recorded at net realisable value with changes in the value of hydrocarbon inventories being adjusted through cost of sales.

Financial instruments

Financial assets and financial liabilities are recognised on the Group's balance sheet when the Group has become a party to the contractual provisions of the instrument.

Trade receivables

Trade receivables are measured at amortised cost using the effective interest method less any impairment.

Cash and cash equivalents

Cash and cash equivalents comprise cash on hand and demand deposits and other short-term highly liquid investments that are readily convertible to a known amount of cash and are subject to an insignificant risk of changes in value.

Financial assets at fair value through profit and loss

Financial assets are held at fair value through profit and loss ("FVTPL") when the financial asset is either held for trading or it is designated as FVTPL. Financial assets at FVTPL are stated at fair value, with any gains or losses arising on re-measurement recognised in profit or loss. The net gain or loss recognised in profit or loss incorporates any dividend or interest earned on the financial asset and is included in the other gains and losses line in the income statement.

Derivative financial instruments

The Group may utilise derivative financial instruments to manage its exposure to oil price risk.

Derivatives are initially recognised at fair value at the date a derivative contract is entered into and are subsequently re-measured to their fair value at each balance sheet date. The resulting gain or loss is recognised in the profit or loss immediately unless the derivative is designated and effective as a hedging instrument, in which event the timing of the recognition in profit or loss depends on the nature of the hedge relationship.

A derivative with a positive fair value is recognised as a financial asset whereas a derivative with a negative fair value is recognised as a liability. A derivative is presented as a non-current asset or a non-current liability if the remaining maturity of the instrument is more than twelve months and it is not expected to be realised or settled within twelve months. Other derivatives are presented as current assets or current liabilities.

Hedge accounting

The Group uses hedge accounting for certain derivative instruments. The Group uses cash flow hedge accounting when hedging the exposure to variability in cash flows that is either attributable to a particular risk associated with a recognised asset or liability or a highly probable forecast transaction or the foreign currency risk in an unrecognised firm commitment.

At the inception of the hedge relationship, the Group formally designates and documents the relationship between the hedging instrument and the hedged item, along with its risk management objectives and its strategy for undertaking the hedge transaction. Furthermore, at the inception of the hedge and on an ongoing basis, the Group documents whether the hedging instrument is highly effective in offsetting changes in fair values or cash flows of the hedged item attributable to the hedged risk, which is when the hedging relationship meets all of the following hedge effectiveness requirements:

- there is an economic relationship between the hedged item and the hedging instrument;
- the effect of credit risk does not dominate the value changes that result from the economic relationship; and
- the hedge ratio of the hedging relationship is the same as that resulting from the quantity of the hedged item that the Group actually hedges and the quantity of the hedging instrument that the Group uses to hedge that quantity of hedged item.

If a hedging relationship ceases to meet the hedge effectiveness requirement relating to the hedge ratio but the risk management objective for that designated hedging relationship remains the same, the Group adjusts the hedge ratio of the hedging relationship (i.e. rebalances the hedge) so that it meets the qualifying criteria again.

The Group designates only the intrinsic value of option contracts as a hedged item, i.e. excluding the time value of the option. The changes in the fair value of the time value of the option are recognised in other comprehensive income and accumulated in the cost of hedging reserve. If the hedged item is transaction-related, the time value is reclassified to profit or loss when the hedged item affects profit or loss. If the hedged item is time-period related, then the amount accumulated in the cost of hedging reserve is reclassified to profit or loss on a rational basis – the Group applies straight-line amortisation. Those reclassified amounts are recognised in profit or loss. If the hedged item is a non-financial item, then the amount accumulated in the cost of hedging reserve is removed directly from equity and included in the initial carrying amount of the recognised non-financial item. Furthermore, if the Group expects that some or all of the profit or loss accumulated in cost of hedging reserve will not be recovered in the future, that amount is immediately reclassified to profit or loss.

Cash flow hedge
The effective portion of changes in the fair value of derivatives and other qualifying hedging instruments that are designated and qualify as cash flow hedges is recognised in other comprehensive income and accumulated under the heading of cash flow hedging reserve, limited to the cumulative change in fair value of the hedged item from inception of the hedge. The gain or loss relating to the ineffective portion is recognised immediately in profit or loss and is included in the revenue line item.

The Group discontinues hedge accounting only when the hedging relationship (or a part thereof) ceases to meet the qualifying criteria (after rebalancing, if applicable). This includes instances when the hedging instrument expires or is sold, terminated or exercised. The discontinuation is accounted for prospectively. Any gain or loss recognised in other comprehensive income and accumulated in cash flow hedge reserve at that time remains in equity and is reclassified to profit or loss when the forecast transaction occurs. When a forecast transaction is no longer expected to occur, the gain or loss accumulated in the cash flow hedge reserve is reclassified immediately to profit or loss.

Impairment of financial assets
The Group recognises a loss allowance for expected credit losses (“ECL”) on trade receivables and contract assets, as well as on financial guarantee contracts. The amount of expected credit losses is updated at each reporting date to reflect changes in credit risk since initial recognition of the respective financial instrument.

The Group always recognises lifetime expected credit losses for trade receivables, contract assets and lease receivables. The expected credit losses on these financial assets are estimated based on observed market data and convention, existing market conditions and forward-looking estimates at the end of each reporting period, including time value of money where appropriate.

For all other financial instruments, the Group recognises lifetime ECL when there has been a significant increase in credit risk since initial recognition. However, if the credit risk on the financial instrument has not increased significantly since initial recognition, the Group measures the loss allowance for that financial instrument at an amount equal to 12-month ECL.

Lifetime ECL represents the expected credit losses that will result from all possible default events over the expected life of a financial instrument. In contrast, 12-month ECL represents the portion of lifetime ECL that is expected to result from default events on a financial instrument that are possible within 12 months after the reporting date.

Financial liabilities and equity
Financial liabilities and equity instruments are classified according to the substance of the contractual arrangements entered into. An equity instrument is any contract that evidences a residual interest in the assets of the Group after deducting all of its liabilities.

Equity instruments
Equity instruments issued by the Company are recorded at the proceeds received, net of direct issue costs, which are charged to share premium.

Borrowings
Interest-bearing loans and overdrafts are recorded at the fair value of proceeds received, net of transaction costs. Finance charges, including premiums payable on settlement or redemption, are accounted for on an accrual basis and are added to the carrying amount of the instrument to the extent that they are not settled in the year in which they arise. The liability is carried at amortised cost using the effective interest rate method until maturity.

Trade payables

Trade payables are stated at amortised cost. The average maturity for trade and other payables is one to three months.

Provisions
Provisions are recognised when the Group has a present obligation as a result of a past event which it is probable will result in an outflow of economic benefits that can be reliably estimated.

Decommissioning provision
Provision for decommissioning is recognised in full when there is an obligation to restore the site to its original condition. The amount recognised is the present value of the estimated future expenditure for restoring the sites of drilled wells and related facilities to their original status. A corresponding amount equivalent to the provision is also recognised as part of the cost of the related oil and gas asset. The amount recognised is reassessed each year in accordance with local conditions and requirements. Any change in the present value of the estimated expenditure is dealt with prospectively. The unwinding of the discount is included as a finance cost.

Share-based payments
Equity-settled share-based payments to employees and others providing similar services are measured at the fair value of the instruments at the grant date. Details regarding the determination of the fair value of equity-settled share-based transactions are set out in note 24. The fair value determined at the grant date of the equity-settled share-based payments is expensed on a straight-line basis over the vesting period, based on the Group's estimate of equity instruments that will eventually vest. At each balance sheet date, the Group revises its estimate of the number of equity instruments expected to vest as a result of the effect of non-market based vesting conditions. The impact of the revision of the original estimates, if any, is recognised in profit or loss such that the cumulative expense reflects the revised estimate, with a corresponding adjustment to equity reserve.

For cash-settled share-based payments, a liability is recognised for the goods or services acquired, measured initially at the fair value of the liability. At each balance sheet date until the liability is settled, and at the date of settlement, the fair value of the liability is re-measured, with any changes in fair value recognised in profit or loss for the period. Details regarding the determination of the fair value of cash-settled share-based transactions are set out in note 24.

Leases

The Group assesses whether a contract contains a lease at inception of the contract. The Group recognises a right-of-use asset and corresponding lease liability in the consolidated balance sheet for all lease arrangements longer than twelve months, where it is the lessee and has control of the asset. For all other leases, the Group recognises the lease payments as an operating expense on a straight-line basis over the term of the lease.

The lease liability is initially measured at the present value of the future lease payments from the commencement date of the lease. The lease payments are discounted using the interest rate implicit in the lease or, if not readily determinable, the company specific incremental borrowing rate.

The lease liability is subsequently measured by increasing the carrying amount to reflect interest on the lease liability (using the effective interest method) and by reducing the carrying amount to reflect the lease payments made. The lease liability is recognised in creditors as current or non current liabilities depending on underlying lease terms.

The right-of-use assets are initially recognised on the balance sheet at cost, which comprises the amount of the initial measurement of the corresponding lease liability, adjusted for any lease payments made at or prior to the commencement date of the lease and any lease incentive received**.**

For short-term leases (periods less than 12 months) and leases of low value, the Group has opted to recognise lease expense on a straight line basis.

Critical accounting judgements and key sources of estimation uncertainty
In the application of the Group's accounting policies, which are described above, the directors are required to make judgements, estimates and assumptions about the carrying amounts of assets and liabilities that are not readily apparent from other sources. The estimates and associated assumptions are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates.

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

Critical judgements in applying the Group's accounting policies
The following are the critical judgements, apart from those involving estimations (which are presented separately below), that the directors have made in the process of applying the Group's accounting policies and that have the most significant effect on the amounts recognised in financial statements.

Revenue
The recognition of revenue, particularly the recognition of revenue from exports, is considered to be a key accounting judgement. The Group began commercial production from the Shaikan Field in July 2013 and historically made sales to both the domestic and export markets. The Group considers that revenue can be only reliably measured when the cash receipt is assured. The assessment of whether cash receipts are assured is based on management's evaluation of the reliability of the MNR's payments to the international oil companies operating in the Kurdistan Region of Iraq.

The judgement is not to recognise revenue in excess of the sum of the cash receipt that is assured and the amount of payables to the MNR that can be offset against amounts due for previously unrecognised revenue in line with the terms of the Shaikan PSC, even though the Group may be entitled to additional revenue under the terms of the Shaikan PSC. Any future agreements between the Company and the KRG might change the amounts of revenue recognised.

Key sources of estimation uncertainty
The key assumptions concerning the future, and other key sources of estimation uncertainty at the reporting period that may 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.

Carrying value of producing assets

In line with the Group's accounting policy on impairment, management performs an impairment review of the Group's oil and gas assets at least annually with reference to indicators as set out in IAS 36. The Group assesses its group of assets, called a cash-generating unit ("CGU"), for impairment, if events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Where indicators are present, management calculates the recoverable amount using key estimates such as future oil prices, estimated production volumes, the cost of development and production, pre-tax discount rates that reflect the current market assessment of the time value of money and risks specific to the asset, commercial reserves and inflation. The key assumptions are subject to change based on market trends and economic conditions. Where the CGU's recoverable amount is lower than the carrying amount, the CGU is considered impaired and is written down to its recoverable amount.

The Group's sole CGU at 31 December 2021 was the Shaikan Field with a carrying value of $402.1 million. The Group performed a full impairment indicator evaluation considering the impact of climate change, oil prices, field productivity, potential changes to future development plans, impacts of local and global geopolitical factors, including the potential inability to access export pipeline due to sanctions (see note 29), and liquidity. The potential impact of such factors together with other possible changes to key assumptions and available mitigating actions, showed that no impairment indicators arose.

The key areas of estimation in the impairment assessment are as follows:

- Commodity prices are based on latest internal forecasts, benchmarked with external sources of information to ensure they are within the range of available market and analyst forecasts.

Scenario	**2022** $/bbl - Real	**2023 onwards** $/bbl - Real
31 December 2021 – base case	$81	$55
31 December 2021 – stress case	$80	$50
31 December 2020 – base case	$55	$55
31 December 2020 – stress case	$40	$40

- The Group continues to develop its assessment of the potential impacts of climate change and the associated risks, the transition to a low-carbon future and our ambition to reduce scope one and two per barrel CO_2 emissions by at least 50% by 2025. The potential effects of climate change and the Paris Agreement were considered. It was concluded, based on benchmarking, that the stress case price deck used in the impairment assessment is reasonable to reflect the potential impact of meeting the Paris Agreement targets. The stress case also includes an estimated cost of the introduction of a carbon tax in Kurdistan;
- Discount rates that are adjusted to reflect risks specific to the Shaikan Field and the KRI. The impairment analysis was based on a post-tax nominal 15% discount rate (2020: 15%). The impact of an increase in the discount rate to 20% was considered to reflect potential increased geopolitical risks and no impairment was identified;
- Operating costs and capital expenditure that are based on financial budgets and internal management forecasts. Costs assumptions incorporate management experience and expectations, as well as the nature and location of the operation and the risks associated therewith. Base case costs assumptions used in the assessment are consistent with the November 2021 draft FDP submitted to the MNR, which includes the estimated cost of implementing a Gas Management Plan, as part of our ambition to reduce scope one and two emissions as outlined above;
- Commercial reserves and production profiles used in the assessment are consistent with the November 2021 draft FDP submitted to the MNR
- Timing of revenue receipts.

In February 2022, a majority decision of the Iraqi Supreme Court ruled that the Kurdistan Region of Iraq Oil and Gas Law ("KROGL") was unconstitutional and provides that the Iraqi Ministry of Oil may pursue annulment of Production Sharing Contracts issued by the Kurdish Regional Government (KRG). The KRG responded that "it will take all constitutional, legal, and judicial measures to protect and preserve all contracts made in the oil and gas sector". While the Iraqi government has disputed the validity of the PSCs and the ruling has not to date impacted our business, it is not possible to determine potential future implications. The Group will continue to engage with Ministry officials on this matter and will react as any implications of the ruling become clearer.

Notes to the consolidated financial statements

1 Geographical information

The Group's non-current assets, excluding deferred tax assets and other financial assets, by geographical location are detailed below:

	2021 **$'000**	2020 Restated $'000
Kurdistan	**402,787**	404,492
United Kingdom	**5,001**	1,910
	407,788	406,402

The Chief Operating Decision Maker, as per the definition in IFRS 8, is considered to be the Board of Directors. The Group operates in a single segment, that of oil and gas exploration, development and production, in a single geographical location, the Kurdistan Region of Iraq. As a result, the financial information of the single segment is the same as set out in the consolidated statement of comprehensive income, the consolidated balance sheet, the consolidated statement of changes in equity, the consolidated cash flow statement and the related notes.

Information about major customers
Included in revenues are $305.1 million, which arose from sales to the KRG (2020: $108.4 million).

2 Revenue

	2021 **$'000**	2020 $'000
Oil sales	**305,142**	108,449
Hedging losses reclassified to revenue	**(3,753)**	-
	301,389	108,449

The Group accounting policy for revenue recognition is set out in the 'Summary of significant accounting policies', with revenue recognised on a cash-assured basis.

During 2021, the cash-assured values recognised as oil sales were the invoiced revenue for the year amounting to $305.1 million (2020: $108.4 million). The oil sales price was calculated using the monthly average Dated Brent price, which was $70.8/bbl on average during the year (2020: $42.0/bbl) less an average discount of $21.20 (2020: $21.10) per barrel for quality and pipeline tariff costs.

Hedging losses were incurred on put options which were purchased to protect against a decline in Dated Brent prices below certain levels. Put options were purchased for 1H 2021 and Q3 2021, effectively establishing a floor price of $35/bbl and $40/bbl, respectively, over approximately 60% of net entitlement production. The put options were designated as cash flow hedges. All the put options expired during the year and the associated hedging losses that had previously been deferred within the hedging reserve were reclassified to revenue.

3 Cost of sales

	2021 **$'000**	2020 $'000
Operating costs	**34,372**	27,401
Capacity building payments	**23,529**	8,362
Changes in inventory valuation	**(348)**	2,923
Depreciation of oil and gas assets	**54,120**	82,797
Depreciation of operational assets	**48**	24
	111,721	121,507

3 Cost of sales continued

Further details on the depreciation of oil and gas assets and operational assets is set out in the Summary of significant accounting policies section.

During the year, the Group received a Competent Person's Report from ERC Equipoise Limited regarding the Shaikan Field's reserves and resources as at 31 December 2020. The use of the future capital expenditure and 2P reserves estimates from the report resulted in a lower depreciation, depletion and amortisation (DD&A) per barrel rate. The new DD&A rate constitutes a change in accounting estimate and is reflected in the financial statements effective 1 January 2021.

4 Other general and administrative expenses

	2021 $'000	2020 $'000
Depreciation and amortisation	**940**	1,325
Auditor's remuneration (see below)	**583**	574
Other general and administrative costs	**12,120**	10,413
	13,643	12,312

Of the $13.6 million of general and administrative expenses, $4.1 million (2020: $5.0 million) were incurred in relation to the Shaikan Field.

	2021 $'000	2020 $'000
Fees payable to the Company's auditor for the audit of the Company's annual accounts	**318**	350[1]
Fees payable to the Company's auditor for other services to the Group		
- audit of the Company's subsidiaries pursuant to legislation	**28**	28
Total audit fees	**346**	378
Advisory services	**107**	45
Other assurance services (including a half year review)	**130**	151
Total fees	**583**	574

[1]The fees payable to the Company's auditor in 2020 included $43,000 in respect of the 2019 audit.

5 Share option related expense

	2021 $'000	2020 $'000
Share-based payment expense	**2,255**	2,440
Payments related to share options exercised	**4,142**	-
Share-based payment related provision for taxes	**2,093**	(1,205)
	8,490	1,235

On the exercise of the Value Creation Plan ("VCP") share options by former Directors, tax settlements were made in cash instead of using the proceeds from selling additional shares. This and the payment of dividends accumulated during the VCP vesting period are the main components of the payments related to share options exercised. As applicable, the future exercise of outstanding VCP share options is expected to be equity settled although the Company may consider settling any related tax in cash.

6 Staff costs

The average number of employees and contractors (including Executive directors) employed by the Group was 349 (2020: 354). The headcount numbers are not adjusted for part-time, shift-work and rotational working arrangements.

Staff costs were as follows:

	2021 $'000	2020 $'000
Wages and salaries	**36,835**	31,753
Social security costs	**1,880**	1,334
Share-based payment (see note 24)	**3,009**	2,637
	41,724	35,724

Staff costs include costs relating to contractors who are long-term workers in key positions, and are included in PPE additions, cost of sales and other general and administrative expenditure depending on the nature of such costs.

7 Finance costs and finance revenue

	2021 $'000	2020 $'000
Notes interest paid during the year (see note 16)	**(10,000)**	(10,000)
Unwinding of finance and arrangement fees (see note 16)	**(489)**	(440)
Finance lease interest	**(123)**	(221)
Put option premium	**-**	(2,662)
Unwinding of discount on provisions (see note 17)	**(741)**	(764)
Total finance costs	**(11,353)**	(14,087)
Finance revenue	**419**	1,278
Net finance costs	**(10,934)**	(12,809)

8 Income tax

	2021 $'000	2020 $'000
Current year credit/(expense)	**75**	(90)
Prior year adjustment	**28**	-
Deferred UK corporation tax credit/(expense) (see note 18)	**771**	(221)
Tax credit/(expense) attributable to the Company and its subsidiaries	**874**	(311)

Under current Bermudian laws, the Group is not required to pay taxes in Bermuda on either income or capital gains. The Group has received an undertaking from the Minister of Finance in Bermuda exempting it from any such taxes at least until the year 2035.

In the Kurdistan Region of Iraq, the Group is subject to corporate income tax on its income from petroleum operations under the Kurdistan PSC. Under the Shaikan PSC, any corporate income tax arising from petroleum operations will be paid from the KRG's share of petroleum profits. Due to the uncertainty over the payment mechanism for oil sales in Kurdistan, it has not been possible to measure reliably the taxation due that has been paid on behalf of the Group by the KRG and therefore the notional tax amounts have not been included in revenue or in the tax charge. This is an accounting presentational issue and there is no taxation to be paid.

The annual UK corporation tax rate for the year ended 31 December 2021 was 19.0% (2020: 19.0%).

8 Income tax *continued*

At the Budget 2021 on 3 March 2021, the UK Government announced that the corporation tax rate in the UK will increase to 25% for companies with profits above £250,000 with effect from 1 April 2023, as well as announcing a number of other changes to allowances and treatment of losses. These changes were substantively enacted as 31 December 2021. Deferred tax is provided for due to the temporary differences, which give rise to such a balance in jurisdictions subject to income tax. All deferred tax arises in the UK.

9 Profit/(loss) per share

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

	2021 **$'000**	2020 $'000
Profit/(loss) after tax for basic and diluted per share calculations	**164,597**	(47,342)
Number of shares ('000s):		
Basic weighted average number of ordinary shares	**213,384**	210,893
Basic EPS (cents)	**77.14**	(22.45)

The Group followed the steps specified by IAS 33 in determining whether potential common shares are dilutive or anti-dilutive.

Reconciliation of dilutive shares:

	2021 **$'000**	2020 $'000
Number of shares ('000s):		
Basic weighted average number of ordinary shares outstanding	**213,384**	210,893
Effect of dilutive potential ordinary shares	**11,962**	-
Diluted number of ordinary shares outstanding	**225,346**	210,893
Diluted EPS (cents)	**73.04**	(22.45)

The weighted average number of ordinary shares in issue excludes shares held by Employee Benefit Trustee ("EBT") and the Exit Event Trustee.

The diluted number of ordinary shares outstanding including share options is calculated on the assumption of conversion of all potentially dilutive ordinary shares.

As the company reported a loss for the year ended 2020, the exercise of the outstanding share options would have reduced the reported loss per share and, therefore, the share options were anti-dilutive.

10 Intangible assets

	Computer software $'000
Year ended 31 December 2020	
Opening net book value	454
Additions	458
Amortisation charge	(3)
Foreign currency translation differences	24
Closing net book value	**933**
At 31 December 2020	
Cost	1,980
Accumulated amortisation	(1,047)
Net book value	**933**
Year ended 31 December 2021	
Opening net book value	933
Additions	2,742
Amortisation charge	(25)
Foreign currency translation differences	(67)
Closing net book value	**3,583**
At 31 December 2021	
Cost	4,722
Accumulated amortisation	(1,139)
Net book value	**3,583**

The amortisation charge of $25,000 (2020: $3,000) for computer software has been included in other general and administrative expenses (see note 4).

11 Property, plant and equipment

	Oil and gas assets $'000	Fixtures and equipment $'000	Right of use assets $'000	Total $'000
Year ended 31 December 2020				
Opening net book value – restated	428,601	1,310	2,596	432,507
Additions	51,716	155	1,721	53,592
Lease modification	-	-	(1,623)	(1,623)
Revision to decommissioning asset	5,100	-	-	5,100
Depreciation charge	(82,797)	(278)	(1,044)	(84,119)
Foreign currency translation differences	-	-	12	12
Closing net book value – restated	**402,620**	**1,187**	**1,662**	**405,469**
At 31 December 2020				
Cost	778,329	7,160	3,602	789,091
Accumulated depreciation	(375,709)	(5,973)	(1,940)	(383,622)
Net book value - restated	**402,620**	**1,187**	**1,662**	**405,469**
Year ended 31 December 2021				
Opening net book value	402,620	1,187	1,662	405,469
Additions	46,165	203	76	46,444
Disposals	-	-	(1,432)	(1,432)
Revision to decommissioning asset	7,429	-	-	7,429
Depreciation charge	(54,120)	(351)	(612)	(55,083)
Accumulated depreciation eliminated on disposal	-	-	1,405	1,405
Foreign currency translation differences	(1)	(6)	(21)	(28)
Closing net book value	**402,094**	**1,033**	**1,078**	**404,205**
At 31 December 2021				
Cost	831,924	7,363	2,246	841,533
Accumulated depreciation	(429,830)	(6,330)	(1,168)	(437,328)
Net book value	**402,094**	**1,033**	**1,078**	**404,205**

The net book value of oil and gas assets at 31 December 2021 is comprised of property, plant and equipment relating to the Shaikan block with a carrying value of $402.1 million (2020 restated: $402.6 million).

The additions to the Shaikan asset during the year include the costs relating to the drilling and completion of SH-14 and SH-13, well flowlines construction, PF-1 and PF-2 debottlenecking activities and subsurface studies. The increase in the decommissioning asset represents further decommissioning obligations that arose on capital projects completed during the year and revisions to decommissioning cost estimates.

The DD&A charge of $54.1 million (2020: $82.8 million) on oil and gas assets has been included within cost of sales (note 3). The depreciation charge of $0.4 million (2020: $0.3 million) on fixtures and equipment and $0.6 million (2020: $1.0 million) on right of use assets has been included in general and administrative expenses (note 4).

Right of use assets at 31 December 2021 of $1.1 million (2020: $1.7 million) consisted principally of buildings.

For details of the key assumptions and judgements underlying the impairment assessment, refer to the "Critical accounting estimates and judgements" section of the Summary of significant accounting policies.

See note 28 for further information on restated balances.

12 Group companies

Details of the Company's subsidiaries and joint operations at 31 December 2021 is as follows:

Name of subsidiary	Place of incorporation	Proportion of ownership interest	Principal activity
Gulf Keystone Petroleum (UK) Limited 6th floor New Fetter Place 8-10 New Fetter Lane London EC4A 1AZ	United Kingdom	100%	Management, support, geological, geophysical and engineering services
Gulf Keystone Petroleum International Limited Cedar House, 3rd Floor 41 Cedar Avenue Hamilton HM12 Bermuda	Bermuda	100%	Exploration, evaluation, development and production activities in Kurdistan

Name of joint operation	Location	Proportion of ownership interest	Principal activity
Shaikan	Kurdistan	80%	Production and development activities

13 Inventories

	31 December 2021	31 December 2020 Restated	1 January 2020 Restated
	$'000	$'000	$'000
Warehouse stocks and materials	**5,318**	5,405	5,230
Crude oil	**700**	355	905
	6,018	5,760	6,135

Warehouse stock and materials at 31 December 2021 contain write downs to net realisable value of nil (2020: $2.5 million) included in cost of sales.

The comparative inventory balances have been restated as items of inventory have been reclassified to property, plant and equipment. See note 28 for further information.

14 Trade and other receivables

Non-current receivables

	2021	2020
	$'000	$'000
Trade receivables	**-**	59,096

14 Trade and other receivables *continued*

Current receivables

	2021 \$'000	2020 \$'000
Trade receivables	**174,634**	34,021
Other receivables	**3,622**	2,963
Prepayments and accrued income	**944**	848
	179,200	37,832

Reconciliation of Trade Receivables

	2021 \$'000	2020 \$'000
Gross carrying amount	**175,754**	101,302
Less: Impairment allowance	**(1,120)**	(8,185)
Carrying value at 31 December	**174,634**	93,117

Gross trade receivables of $175.8 million (2020: $101.3 million) are comprised of invoiced amounts due from the KRG for crude oil sales totalling $163.6 million (2020: $92.2 million) and a share of Shaikan revenue arrears the Group purchased from MOL amounting to $12.2 million (2020: $9.1 million). The amount due for crude oil sales includes past due trade receivables of $43.1 million[1] (2020: $77.3 million) related to November 2019 to February 2020 invoices.

While the Group expects to recover the full value of the outstanding invoices and purchased revenue arrears, the ECL on the overdue receivable balance of $1.1 million (2020: $8.2 million) was provided against the receivables balance in line with the requirements of IFRS 9. During the year, a $7.1 million gain was recognised due to the reduction of the ECL provision (2020: a loss of $6.8 million due to the increase of the ECL provision), driven by a lower arrears balance.

The Group continues to receive payments in relation to the arrears from the outstanding invoices in line with the KRG's proposal to pay 20% of the difference between the monthly average dated Brent price and $50/bbl multiplied by the gross Shaikan crude oil volumes sold in the month.

[1] The past due invoiced trade receivables amount excludes the associated capacity building payments due to the KRG which reduce the amount due to GKP to $41.0 million (2020: $73.3 million).

ECL sensitivities

The Group's profit before tax was not sensitive to movements of +/-10% in production level, Brent price, loss given default or probability of default.

Other receivables

Included within Other receivables is an amount of $0.4 million (2020: $0.4 million) being the deposits for leased assets which are receivable after more than one year. There are no receivables from related parties as at 31 December 2021 (2020: nil). No impairments of other receivables have been recognised during the year (2020: nil).

15 Trade and other payables

Trade and other payables principally comprise amounts outstanding for trade purchases and ongoing costs.

The directors consider that the carrying amount of trade payables approximates their fair value.

15 Trade and other payables *continued*

Current liabilities

	2021 $'000	2020 $'000
Trade payables	**6,494**	2,212
Accrued expenditures	**25,961**	14,481
Other payables	**65,927**	51,612
Current lease liabilities (see note 22)	**419**	718
Tax liabilities	**-**	100
	98,800	69,123

Accrued expenditures include $4.4 million interest payable as at 31 December 2021 (2020: $4.4 million), see note 16.

Other payables include $56.4 million (2020: $46.5 million) of amounts payable to the KRG that are not expected to be paid, but rather offset against revenue due from the KRG related to pre-October 2017 oil sales, which have not yet been recognised in the financial statements. Within this amount, $22.6 million (2020: $14.8 million) relates to a non-cash payable for the difference between the capacity building rate of 20% and 30% (see Summary of significant accounting policies, Sales revenue).

Non-current liabilities

	2021 $'000	2020 $'000
Non-current lease liability (see note 22)	**789**	1,058

16 Long term borrowings

	2021 $'000	2020 $'000
Liability component at 1 January	**102,993**	102,553
Interest expense, including unwinding of finance and arrangement fees	**10,489**	10,440
Interest paid during the year	**(10,000)**	(10,000)
Liability component at 31 December	**103,482**	102,993

Liability component reported in:

	2021 $'000	2020 $'000
Current liabilities (see note 15)	**4,359**	4,360
Non-current liabilities	**99,123**	98,633
	103,482	102,993

In July 2018, the Group completed the private placement of a 5-year senior unsecured $100 million bond issue (the "Notes"). The unsecured Notes are guaranteed by Gulf Keystone Petroleum International Limited and Gulf Keystone Petroleum (UK) Limited, two of the Company's subsidiaries, and the key terms are summarised as follows:

- maturity date is 25 July 2023;
- at any time prior to maturity, the Notes are redeemable by GKP in part or full with a prepayment penalty;
- the interest rate is 10% per annum with semi-annual payment dates; and
- the Company is permitted to raise up to $200 million of additional indebtedness at any time on market terms to fund capital and operating expenditure, subject to certain requirements.

During the year, the Group was not in breach of any terms of the Notes.

16 Long term borrowings *continued*

The Notes are traded on the Norwegian Stock Exchange and the fair value at the prevailing market price as at the balance sheet date was:

	Market price	**2021 $'000**	2020 $'000
Notes	$103.75	**103,750**	102,500

As at 31 December 2021, the Group's remaining contractual liability comprising principal and interest based on undiscounted cash flows is as follows:

	2021 $'000	2020 $'000
Within one year	**10,000**	10,000
Within two years	**105,639**	115,639
	115,639	125,639

17 Provisions

Decommissioning provision	**2021 $'000**	2020 $'000
At 1 January	**35,671**	29,807
New provisions and changes in estimates	**7,429**	5,100
Unwinding of discount	**741**	764
At 31 December	**43,841**	35,671

The provision for decommissioning is based on the net present value of the Group's estimated share of expenditure, inflated at 2.0% (2020: 2.0%) and discounted at 2.0% (2020: 2.0%), which may be incurred for the removal and decommissioning of the wells and facilities currently in place and restoration of the sites to their original state. Most expenditures are expected to take place towards the end of the PSC term in 2043.

18 Deferred tax asset

The following are the major deferred tax liabilities and assets recognised by the Group and movements thereon during the current and prior reporting periods. The deferred tax assets arise in the United Kingdom.

	Accelerated tax depreciation $'000	**Share-based payments $'000**	**Tax losses carried forward $'000**	**Total $'000**
At 1 January 2020	**(27)**	**801**	**75**	**849**
(Charge)/credit to income statement	(85)	(66)	(70)	(221)
Exchange differences	(3)	(3)	(5)	(11)
At 31 December 2020	**(115)**	**732**	**-**	**617**
(Charge)/credit to income statement	(381)	321	831	771
Exchange differences	1	(4)	-	(3)
At 31 December 2021	**(495)**	**1,049**	**831**	**1,385**

19 Financial instruments

	2021 $'000	2020 $'000
Financial assets		
Cash and cash equivalents	**169,866**	147,826
Receivables	**178,258**	97,776
	348,124	245,602
Derivative financial instruments		
Put options used for hedging	**-**	977
	348,124	246,579
Financial liabilities		
Trade and other payables	**99,589**	70,081
Borrowings	**99,123**	98,633
	198,712	168,714

All financial liabilities, except for Borrowings (see note 16) and non-current lease liabilities (see note 15), are due to be settled within one year and are classified as current liabilities. All financial liabilities are recognised at amortised cost.

The maturity profile and fair values of the Notes are disclosed in note 16. The maturity profile of all other financial liabilities is indicated by their classification in the balance sheet as "Current" or "Non-current". Further information relevant to the Group's liquidity position is disclosed in the Directors' Report under "Going Concern".

Fair values of financial assets and liabilities

With the exception of the Notes, and the receivables from the KRG which the Group expects to recover in full (see note 14), the Group considers the carrying value of all its financial assets and liabilities to be materially the same as their fair value. The fair value of the Notes, as determined using market values at 31 December 2021, was $103.8 million (2020: $102.5 million) compared to the carrying value of $99.1 million (2020: $98.6 million).

In making the above assessment, consideration has been given to the fair value hierarchy set out in IFRS 13. Fair value hierarchy levels 1 to 3 are based on the degree to which the fair value is observable:

- Level 1 fair value measurements are those derived from quoted prices (unadjusted) in active markets for identical assets or liabilities;
- Level 2 fair value measurements are those derived from inputs other than quoted prices included with Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices); and
- Level 3 fair value measurements are those derived from valuation techniques that include inputs for the asset or liability that are not based on observable market date (unobservable inputs).

The fair value of the Notes disclosed above is based on Level 1 in the hierarchy.

The financial assets balance includes an $1.1 million provision against trade receivables (2020: $8.2 million) (see note 14). All financial assets, except derivatives designated as a hedge, are measured at amortised cost.

Capital Risk Management

The Group manages its capital to ensure that the entities within the Group will be able to continue as going concerns while maximising the return to stakeholders through the optimisation of the debt and equity structure. The capital structure of the Group consists of cash, cash equivalents, Notes and equity attributable to equity holders of the parent. Equity comprises issued capital, reserves and accumulated losses as disclosed in note 20 and the Consolidated Statement of Changes in Equity.

19 Financial instruments *continued*

Capital Structure
The Group's Board of Directors reviews the capital structure on a regular basis and will make adjustments in light of changes in economic conditions. As part of this review, the Board considers the cost of capital and the risks associated with each class of capital.

Significant Accounting Policies
Details of the significant accounting policies and methods adopted, including the criteria for recognition, the basis of measurement and the basis on which income and expenses are recognised, in respect of each class of financial asset, financial liability and equity instrument are disclosed in the Summary of Significant Accounting Policies.

Financial Risk Management Objectives
The Group's management monitors and manages the financial risks relating to the operations of the Group. These financial risks include market risk (including commodity price, currency and fair value interest rate risk), credit risk, liquidity risk and cash flow interest rate risk.

As at year end, the Group did not hold any derivative assets to hedge against commodity price declines or any other financial risks. The Group does not use derivative financial instruments for speculative purposes.

The risks are closely reviewed by the Board on a regular basis and, where appropriate, steps are taken to ensure these risks are minimised.

Market risk
The Group's activities expose it primarily to the financial risks of changes in, oil prices, foreign currency exchange rates and changes in interest rates in relation to the Group's cash balances.

There have been no changes to the Group's exposure to other market risks. The risks are monitored by the Board on a regular basis.

The Group conducts and manages its business predominantly in US dollars, the operating currency of the industry in which it operates. The Group also purchases the operating currencies of the countries in which it operates routinely on the spot market. Cash balances are held in other currencies to meet immediate operating and administrative expenses or to comply with local currency regulations.

At 31 December 2021, a 10% weakening or strengthening of the US dollar against the other currencies in which the Group's monetary assets and monetary liabilities are denominated would not have a material effect on the Group's net assets or profit before tax.

Interest rate risk management
The Group's policy on interest rate management is agreed at the Board level and is reviewed on an ongoing basis. The current policy is to maintain a certain amount of funds in the form of cash for short-term liabilities and have the rest on relatively short-term deposits, usually between one and three months, to maximise returns and accessibility. The Group must pay interest on its Notes semi-annually in cash at 10% per annum.

Based on the exposure to the interest rates for cash and cash equivalents at the balance sheet date, a 0.5% increase or decrease in interest rates would not have a material impact on the Group's profit for the year or the previous year. A rate of 0.5% is used as it represents management's assessment of a reasonable change in interest rates.

19 Financial instruments *continued*

Credit risk management
Credit risk refers to the risk that a counterparty will default on its contractual obligations resulting in financial loss to the Group. As at 31 December 2021, the maximum exposure to credit risk from a trade receivable outstanding from one customer is $175.8 million (2020: $101.3 million). Although the Group is confident in the recovery of the trade receivables balance, a provision of $1.1 million (2020: $8.2 million) was recognised against the trade receivables balance.

The credit risk on liquid funds is limited because the counterparties for a significant portion of the cash and cash equivalents at the balance sheet date are banks with investment grade credit ratings assigned by international credit-rating agencies.

Liquidity risk management
Ultimate responsibility for liquidity risk management rests with the Board of Directors. It is the Group's policy to finance its business by means of internally generated funds, external share capital and debt. The Group seeks to raise further funding as and when required.

Fair value of derivative instruments
All derivatives are used to hedge against commodity price risk and are recognised at fair value on the balance sheet with valuation changes recognised immediately in the income statement unless the derivatives have been designated as a cash flow hedge. Fair value is the amount for which the asset or liability could be exchanged in an arm's length transaction at the relevant date. Where available, fair values are determined using quoted prices in active markets. To the extent that market prices are not available, fair values are estimated by reference to market-based transactions or using standard calculation techniques for the applicable instruments and commodities involved.

For derivatives designated as a cash flow hedge, the movements in the fair value of the derivatives are recognised in other comprehensive income. Derivatives' maturity and the timing of their recycling into income or expense coincide.

The Group's derivative instruments' value was as following:

	2021 $'000	**2020 $'000**
Derivatives that are designated and effective as hedging instruments carried at fair value:		
Put option	-	977
	-	977

To manage the Group's oil price risk, put options were entered into during the year. The first tranche related to H1 2021 and was entered into at a cost of $2.7 million hedging 1.6 Mbbl with a floor price of $35/bbl. A second tranche related to Q3 2021 was entered into at a cost of $1.0 million hedging 0.8 Mbbl with a floor price of $40/bbl. Costs relating to the put options have been recognised in revenue (see Note 2).

20 Share capital

	2021 $'000	2020 $'000
Authorised		
Common shares of $1 each (2020: $1 each)	**231,605**	231,605
Non-voting shares of $0.01 each	**500**	500
Preferred shares of $1,000 each	**20,000**	20,000
Series A Preferred shares of $1,000 each	**40,000**	40,000
	292,105	292,105

	Common shares			
	No. of shares '000	**Amount $'000**	**Share capital $'000**	**Share premium $'000**
Balance 1 January 2020	**229,430**	**1,101,105**	**229,430**	**871,675**
Shares cancelled	(18,059)	(46,820)	(18,059)	(28,761)
Balance 31 December 2020	**211,371**	**1,054,285**	**211,371**	**842,914**
Dividends paid	-	(100,000)	-	(100,000)
Shares issued	2,360	2,360	2,360	-
Balance 31 December 2021	**213,731**	**956,645**	**213,731**	**742,914**

At 31 December 2021, a total of nil (2020: 1,000,000) common shares were held in treasury with a value of nil (2020: $2.6 million)

At 31 December 2021, a total of 0.1 million common shares at $1 each were held by the EBT and Exit Event Trustee (2020: 0.1 million at $1 each). These common shares were included within reserves.

In 2019 and 2020, the company carried out two buy-back programmes. Following the buy-back programmes completion, the Company held 19,059,064 shares in treasury of which 18,059,064 were cancelled in late 2020.

Rights attached to share capital
The holders of the common shares have the following rights (subject to the other provisions of the Byelaws):

(i) entitled to one vote per common share;
(ii) entitled to receive notice of, and attend and vote at, general meetings of the Company;
(iii) entitled to dividends or other distributions; and
(iv) in the event of a winding-up or dissolution of the Company, whether voluntary or involuntary or for a reorganisation or otherwise or upon a distribution of capital, entitled to receive the amount of capital paid up on their common shares and to participate further in the surplus assets of the Company only after payment of the Series A Liquidation Value (as defined in the Byelaws) on the Series A Preferred Shares.

21 Cash flow reconciliation

	Notes	2021 $'000	2020 Restated[1] $'000
Cash flows from operating activities			
Profit/(loss) from operations		**174,600**	(33,381)
Adjustments for:			
Depreciation, depletion and amortisation of property, plant and equipment (including the right of use assets)		**55,111**	84,119
Amortisation of intangible assets		**25**	3
(Decrease)/increase of provision for impairment of trade receivables	14	**(7,065)**	6,776
Put option hedging losses reclassified to revenue		**3,752**	-
Share-based payment expense	24	**1,197**	2,440
Lease modification		**-**	(97)
Operating cash flows before movements in working capital		**227,620**	59,860
Increase in inventories		**(258)**	374[1]
Increase in trade and other receivables		**(75,259)**	(523)
Increase / (decrease) in trade and other payables		**36,977**	(2,977)
Income taxes received		**75**	-
Cash generated from operations		**189,155**	56,734[1]

Reconciliation of property, plant and equipment additions to cash flows from purchase of property, plant and equipment:

	2021 $'000	2020 Restated $'000
Associated cash flows		
Additions to property, plant and equipment	**46,417**	53,592[1]
Movement in working capital	**6,927**	12,087
Non-cash movements		
Finance lease additions	**-**	(1,721)
Capitalised share option charges	**(409)**	(197)
Foreign exchange differences	**24**	(1)[1]
Purchase of property, plant and equipment	**52,959**	63,760

[1]The comparative cash flow reconciliation has been restated. For further details, see the Statement of cash flows.

Movement in financing related liabilities

The Group's financing related liabilities are comprised of borrowings and lease liabilities. The movements in borrowings are shown in note 16 and the movements in lease liabilities in the year were primarily cash payments of $0.7 million.

22 Lease Liabilities

	2021 $'000	2020 $'000
Analysed as:		
Current liabilities (note 15)	**419**	718
Non-current liabilities (note 15)	**789**	1,058
	1,208	1,776
Lease liability maturity analysis		
Year 1	**419**	209
Year 2	**789**	48
Year 3	**-**	-
Year 4	**-**	1,519
Amounts payable under leases		
Within one year	**509**	720
In the second to fifth year inclusive	**868**	1,396
	1,377	2,116
Less future interest charges	**(169)**	(340)
Net present value of lease obligations	**1,208**	1,776

23 Commitments

Exploration and development commitments

Additions to property, plant and equipment are generally funded with the cash flow generated from the Shaikan Field. As at 31 December 2021, gross capital commitments in relation to the Shaikan Field were estimated to be $20.6 million (2020: $0.6 million).

24 Share-based payments

	2021 $'000	2020 $'000
Total share options charge	**2,664**	2,637
Capitalised share options charge	**(409)**	(197)
Share options charge in Income Statement	**2,255**	2,440

Value Creation Plan ("VCP")

The VCP was approved by shareholders in December 2016. As at 31 December 2021, 3.5 million nil-cost share options were outstanding under the VCP. There will be no further awards under the plan.

Outstanding awards will vest subject to the Company achieving a Total Shareholder Return ("TSR") of at least 8% compound annual growth, in accordance with the VCP rules. Subject to achieving the requisite TSR, all the outstanding share options will vest following the Measurement Date for the financial year ending on 31 December 2021.

The requisite TSR was achieved following the Measurement date for the financial year ended 31 December 2020. The measurement date for the financial year ended 31 December 2021 has not yet passed as at the date of this report.

24 Share-based payments *continued*

	2021 Number of share options ’000	2020 Number of share options ’000
Outstanding at 1 January	**7,017**	7,017
Exercised during the year	**(3,509)**	-
Outstanding at 31 December	**3,508**	7,017
Exercisable at 31 December	**3,508**	-

The options outstanding at 31 December 2021 had a weighted average remaining contractual life of less than one year.

A charge of $0.1 million (2020: $0.8 million) in relation to the VCP is included in the total share options charge.

Staff Retention Plan

At the 2016 Annual General Meeting (“AGM”), shareholders approved the adoption of the Gulf Keystone Petroleum 2016 Staff Retention Plan (“SRP”), which is designed to reward members of staff through the grant of share options at a zero exercise price.

The exercise of the nil-cost awarded options is not subject to any performance conditions and can be exercised at any time after the three year vesting period but within ten years after the date of grant. If options are not exercised within ten years, the options will lapse and will not be exercisable. If an employee leaves the company during the three years from the date of grant, the options will lapse on the date notice to leave is given to the company. Should an employee be regarded as a good leaver, the options may be exercised at any time within a period of six months from departure date.

	2021 Number of share options ’000	2020 Number of share options ’000
Outstanding at 1 January	**973**	1,129
Exercised during the year	**(908)**	(156)
Outstanding at 31 December	**65**	973
Exercisable at 31 December	**65**	973

The weighted average share price at the date of exercise for share options exercised during the year was £1.70 (2020: £1.43).

During the year no options (2020: nil) were granted to employees under the Group’s SRP.

A charge of nil (2020: $0.1 million) in relation to the SRP is included in the total share options charge.

Share options outstanding at the end of the year have the exercise price of nil and the following expiry dates:

24 Share-based payments *continued*

Staff Retention Plan (continued)

Expiry date	Options ('000)	
	2021	2020
11 December 2026	**12**	516
9 January 2027	**-**	250
30 June 2027	**53**	207
	65	973

The options outstanding at 31 December 2021 had a weighted average remaining contractual life of 5 years.

Long Term Incentive Plan

The Gulf Keystone Petroleum 2014 Long Term Incentive Plan ("LTIP") is designed to reward members of staff through the grant of share options at a zero exercise price, that vest three years after grant, subject to the fulfilment of specified performance conditions. These performance conditions are 50% TSR over the vesting period and 50% the Group's TSR relative to a bespoke group of comparators.

	2021 Number of share options '000	2020 Number of share options '000
Outstanding at 1 January	**7,254**	2,629
Granted during the year	**2,747**	4,752
Exercised during the year	**(1,014)**	-
Forfeited during the year	**(712)**	(127)
Outstanding at 31 December	**8,275**	7,254
Exercisable at 31 December	**-**	-

The weighted average share price at the date of exercise for share options exercised during the year was £1.69 (2020: n/a).

The inputs into the calculation of fair values of the shares granted during the year are as follows:

	2021	2020
Weighted average share price	**£2.26**	£0.88
Weighted average exercise price	**Nil**	Nil
Expected volatility	**58.7%**	54.6%
Expected life	**3 years**	3 years
Risk-free rate	**0.14%**	0.08%
Expected dividend yield (on the basis dividends equivalents received)	**Nil**	Nil

The options outstanding at 31 December 2021 had a weighted average remaining contractual life of 2 years.

The aggregate of the estimated fair value of options granted in 2021 is $4.3 million (2020 $2.6 million).

A charge of $2.5 million (2020: $1.7 million) in relation to the LTIP is included in the total share options charge.

25 Dividend

During 2021, an ordinary dividend of $25 million (11.697 US cents per Common Share) was paid, followed by a special dividend of $25 million (11.697 US cents per Common Share) and an interim dividend for 2021 of $50 million (23.394 US cents per Common Share) (2020: no dividends were paid). To date in 2022, an interim dividend of $50 million has been paid. A further $65 million interim dividend is expected to be paid on 13 May 2022, based on a record date of 29 April 2022 and ex-dividend date of 28 April 2022. An ordinary dividend of $25 million is subject to approval at the AGM on 24 June 2022 and will be paid to shareholders on 15 July 2022 based on a record date of 1 July 2022.

26 Related party transactions

The Group has a related party relationship with its subsidiaries. The Company and its subsidiaries, in the ordinary course of business, enter into various sales, purchase and service transactions with joint operations in which the Group has a material interest. These transactions are under terms that are no less favourable to the Group than those arranged with third parties.

Remuneration of Directors and Officers

The remuneration of the Directors and Officers who are considered to be key management personnel is set out below in aggregate for each of the categories specified in IAS 24 Related Party Disclosures. The Directors and Officers who served during the year ended 31 December 2021 were as follows:

J Huijskes – Non-Executive Chairman
M Angle – Deputy Chairman
G Soden – Non-Executive Director
D Thomas – Non-Executive Director
K Wood – Non-Executive Director
J Harris – Chief Executive Officer – (appointed 4 January 2021)
I Weatherdon – Chief Financial Officer
S Catterall – Chief Operations Officer (resigned 18 February 2022)
G Papineau-Legris – Chief Commercial Officer
J Barker – HR Director (resigned 10 September 2021)
C Kinahan – Chief Human Resources Officer (appointed 2 August 2021)
A Robinson – Chief Legal Officer and Company Secretary

The values below are calculated in accordance with IAS 19 and IFRS 2.

	2021 $'000	2020 $'000
Short-term employee benefits	**5,809**	4,822
Share-based payment - options	**1,012**	1,273
	6,821	6,095

Further information about the remuneration of individual Directors is provided in the Directors' Emoluments section of the Remuneration Committee Report.

27 Contingent liabilities

The Group has a contingent liability of $27.3 million (2020: $27.3 million) in relation to the proceeds from the sale of test production in the period prior to the approval of the original Shaikan Field Development Plan ("FDP") in July 2013. The Shaikan PSC does not appear to address expressly any party's rights to this pre-FDP petroleum. The sales were made based on sales contracts with domestic offtakers which were approved by the KRG. The Group believes that the receipts from these sales of pre-FDP petroleum are for the account of the Contractor, rather than the KRG and accordingly recorded them as test revenue in prior years. However, the KRG has requested a repayment of these amounts and the Group is currently involved in negotiations to resolve this matter. The Group has received external legal advice and continues to maintain that pre-FDP petroleum receipts are for the account of the Contractor. This contingent liability forms part of the ongoing Shaikan PSC amendment negotiations and it is likely that it will be settled as part of those negotiations.

28 Prior year restatement

The Group has identified that prior year inventory balances contained certain equipment to be used in the development of the Shaikan Field, which will be consumed over a period in excess of one year. The Group determined that this equipment met the definition of property, plant and equipment as defined by "IAS 16 – Property, plant and equipment" and has restated the prior year financial statements to reflect this reclassification.

Comparative figures for the reclassification have been presented in the balance sheet and statement of cash flows, as detailed below. There is no impact to the income statement.

Consolidated balance sheet

	1 January 2020 As previously reported $'000	Reclassification of inventory $'000	**1 January 2020 Restated $'000**
Property, plant and equipment	407,602	24,905	**432,507**
Inventories	31,040	(24,905)	**6,135**

	31 December 2020 As previously reported $'000	Reclassification of inventory $'000	**31 December 2020 Restated $'000**
Property, plant and equipment	374,702	30,767	**405,469**
Inventories	36,527	(30,767)	**5,760**

Statement of cash flows

	31 December 2020 As previously reported $'000	Reclassification of inventory $'000	**31 December 2020 Restated $'000**
Cash generated from operations	50,873	5,862	**56,734**
Purchase of property, plant and equipment	(57,899)	(5,862)	**(63,760)**

29 Subsequent events

Iraqi Supreme Court ruling
In February 2022, the Iraqi Supreme Court ruled that the Kurdistan Region of Iraq Oil and Gas Law is unconstitutional. The ruling also provides that the Iraqi Ministry of Oil may pursue annulment of Production Sharing Contracts issued by the KRG. The KRG responded that "it will take all constitutional, legal, and judicial measures to protect and preserve all contracts made in the oil and gas sector". The ruling has not impacted the Company's operations and the Company is continuing to monitor the situation closely.

Export route availability
The Company currently exports all of its crude oil through the Kurdistan Export Pipeline, which is 60% owned by Rosneft. As a result of Russia's invasion of Ukraine on 24 February 2022, the Company is monitoring the evolving sanctions situation as certain specific sanctions on Rosneft could impact the Company's ability to access this pipeline.