SOCO International plc

(“SOCO” or the “Company” or, together with its subsidiaries, the “Group”)

2017 PRELIMINARY RESULTS

SOCO, an international oil and gas exploration and production company, today announces its preliminary results for the year ended 31 December 2017.

Ed Story, President and Chief Executive Officer of SOCO, commented,

“2017 saw the further return of cash to shareholders, stable production, and a renewed focus on SOCO’s business strategy. Combined with a strong balance sheet, low operating costs and continued financial discipline the Company is well positioned for growth. The two key achievements this year were the approval of an updated FFDP for the TGT field and securing the PSC for Blocks 125 & 126, offshore central Vietnam. We continue to have a core belief in delivering total shareholder value and we are today announcing a recommended final dividend for 2017 of 5.25 pence per share. To add to the commitment to an annual dividend, a business development team was established in 2017 to emphasise the Company’s commitment to capital growth. In 2017 the team considered a number of opportunities and, although the merger with Kuwait Energy did not materialise, SOCO continues to pursue growth opportunities of scale, which meet our investment criteria. We have the right people and the right financial strength to create opportunities to grow the business and we look forward to delivering in 2018”.

2017 FINANCIAL HIGHLIGHTS

- Strong and robust balance sheet, zero debt, solid cash flow, and low cash operating costs:
    - Revenue of $156.2m (2016: $154.6m), an average realised crude oil price of $56/bbl (2016: $45/bbl), a premium to Brent of over $2/bbl
    - $45.0m of cash generated from operations (2016: $46.0m)
    - Loss of $157.3m (2016: $4.2m restated), including E&E write offs of $152.3m (2016: $2.2m write back restated). Loss prior to E&E impact of $5.0m (2016: $6.4m restated)
    - Year-end cash and liquid investment balance of $137.7m (2016: $100.3m) and no debt
    - Receipt of the remaining proceeds of $42.7m associated with the disposal of our Mongolia assets
    - Low cash operating expenditure of $13.73/boe (2016: $11.70/boe)*
    - 2017 cash capital expenditure of $29.3m (2016: $40.1m), was fully funded from existing cash resources
- Recommended dividend of 5.25 pence per share (approx. $24.3m)
    - Dividends to shareholders during 2017 of $21.0m (2016: $17.5m)

*See Non-IFRS measures note 12

2017 OPERATIONAL HIGHLIGHTS

- Low cost net production average of 8,276 BOEPD (2016: 9,883 BOEPD) in line with guidance - TGT production averaged 6,724 BOEPD (2016: 8,330 BOEPD) and CNV production averaged 1,552 BOEPD (2016: 1,553 BOEPD)

- Updated FFDP for the TGT field, offshore southern Vietnam, which was approved in February 2017 allowing for:
    - Installation of new processing equipment on the TGT H1-WHP, completed to allow for higher levels of liquid handling
    - Two infill wells, TGT-30P on the H1-WHP and TGT-29P on the H5-WHP, which were executed on time and within budget
- A PSC for Blocks 125 & 126, offshore central Vietnam, was signed in October 2017, awarding SOCO a 70% operated interest over the two blocks
- New 25-year PEXs awarded over each of the Viodo, Lideka and Loubana areas within the former Marine XI Block, offshore Congo (Brazzaville)
- Group year-end 2017 commercial (2P) reserves of 28.1 MMboe (2016: 33.3 MMboe)

OUTLOOK FOR 2018

- Production guidance of 8,000 to 9,000 BOEPD net with production levels above this dependent upon the outcome of the 2018 drilling programme on TGT and CNV
- 2018 capex of approx. $40m fully funded from existing cash resources, to cover the development drilling and infrastructure upgrade on our existing Vietnam assets and purchase, processing and interpretation of seismic data for our new venture Blocks 125 & 126 offshore Vietnam
- Maintaining commitment to sustainable cash flow generation and returns to shareholders
- Continued pursuit of new business opportunities to transform the business in line with our financial strategy of capital discipline, capital allocation and capital return

ENQUIRIES:

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NOTES TO EDITORS

SOCO is an international oil and gas exploration and production company headquartered in London, admitted to the premium listing segment of the Official List and traded on the main market of the London Stock Exchange. The Group has field development and production interests in Vietnam and exploration and appraisal interests in the Republic of Congo (Brazzaville) and Angola.

CHAIRMAN AND CHIEF EXECUTIVE OFFICER'S STATEMENT

POISED FOR GROWTH

2017 saw a year where SOCO retained its stable financial position with a renewed focus and commitment on actively pursuing growth opportunities being emphasised with the establishment of a business development team. This combination places the Group on a robust platform from which to materially grow the business.

Operations in 2017 centred on optimising production efficiency on the TGT and CNV fields in our core business area, offshore southern Vietnam. Formal approval of the updated FFDP for TGT in February 2017 signalled a positive realignment amongst partners and a halt to the production decline. Group production was 8,276 BOEPD (2016: 9,883 BOEPD) net to SOCO's working interest. Group year-end 2017 commercial (2P) reserves are 28.1 MMboe (2016: 33.3 MMboe).

SOCO continues to achieve a stable operational and financial base with the balance sheet remaining strong throughout 2017 with solid cash flow and low cash operating costs. The Group finished the year with no debt and $137.7m in Cash after fully funding its operating and capital expenditure programme and returning $21.0m to shareholders through a 5 pence per share dividend, bringing the total return to shareholders since 2006 to $476m. In March 2017, the Group received $42.7m as the final payment from the 2005 sale of its Mongolia assets.

Capex in 2017, fully funded from existing cash resources, was $29.3m (2016: $40.1m). Net cash generated from operations fell slightly to $45.0m in 2017, from $46.0m in 2016, reflecting higher oil prices offset by a decrease in production and timing of working capital movements and cash tax. An average crude oil sales price of $56/bbl as realised during 2017, representing a premium of over $2/bbl to Brent and generating revenues of $156.2m (2016: $154.6m), against low cash operating expenditure of $13.73/bbl (2016: $11.70/bbl). SOCO's full operating cost break-even oil price per barrel is below $30. The Group posted a loss of $157.3m (2016: $4.2m restated), which included E&E impairments of $152.3m (2016: $2.2m write back restated), the loss being $5.0m (2016: $6.4m loss restated) prior to the impairment. As announced in our Trading statement in January we have determined that there will be no substantive activity on our African assets and accordingly they have been fully impaired. Prior year comparatives have been restated to reflect our decision to change our E&E policy from modified full cost to successful efforts to better align with our peer group.

Vietnam is the core asset in SOCO's portfolio and since 1997 we have invested over $1.1 billion in the region, making SOCO one of the largest British investors in Vietnam. The ultimate goal of any successful development is to achieve production in a safe, responsible and cost effective way to benefit all stakeholders, including the countries where we operate. Safety will always be of the highest priority within the business and SOCO's joint-operations have achieved an outstanding record of safety and have demonstrated commitment to local sourcing, employment, training and industry upskilling. Our interests in the TGT and CNV fields are operated by the HLJOC and HVJOC respectively. We are delighted by HLHVJOC's extremely high level of safe operations, with zero LTIs in almost 22.9 million man-hours worked since project inception, representing six production years on TGT and nine production years on CNV.

Our goal is to be a positive presence in the regions in which we operate, by providing responsible and sustainable development, resulting in value for the host countries and local communities as well as for our own shareholders. SOCO continually strives to select and finance social projects which are sustainable and will outlast the company's involvement in the project. In Vietnam, community projects are selected by HLHVJOC and during 2017, the HLHVJOC Charitable Donation programme focused on projects assisting infrastructure development, investing in healthcare, education, and disaster relief for flood victims.

This year SOCO reinvigorated its corporate focus to further strengthen the business through inorganic and organic growth opportunities, with the potential to upscale the business underpinned by our historical focus on financial discipline and shareholder return.

NEW VENTURES

SOCO has been present in Vietnam for over 20 years, and because of our experience and presence in the region, we began evaluation of the exploration potential of Blocks 125 & 126 in the Phu Khanh Basin, in 2010. We are delighted to have signed a PSC in 2017 under which the group has acquired 70% operated interest over the two blocks, and this is seen as a strategic extension of our existing core asset. In Africa, activity centred on the award of new PEXs over each of Viodo, Lideka and Loubana, in addition to the already granted PEX for Lidongo. All four new exploitation permits are within what was formerly the contract area of the Marine XI PSC offshore Congo.

In October 2017, the Group signed a PSC for Blocks 125 & 126, in the Phu Khanh Basin offshore central Vietnam, with PetroVietnam and SOCO's co-venturer, SOVICO Holdings Company, under which the Group has acquired 70% operated interest over the two blocks. Blocks 125 & 126 are in moderate to deep water in the Phu Khanh Basin, to the north of the Cuu Long Basin, and have multiple structural and stratigraphic plays observed on the available seismic data. Initial activities will include reprocessing and interpretation of seismic data, with a view to a first exploration well potentially as early as 2020.

In January 2018, SOCO announced that it was in preliminary discussions with the newly-constituted Board of Directors of Kuwait Energy plc ("Kuwait Energy") regarding a potential transaction. On 5 March 2018 we announced that these discussions were terminated, with the Company unable to reach agreement with Kuwait Energy on the basis for an acceptable transaction.

The SOCO team has a track record of delivering shareholder value through asset acquisition and monetisation, delivering large scale developments, and returning capital to shareholders. We evaluate M&A opportunities by reference to our strategic, financial and operational criteria and only pursue transactions if they are determined by the Board to be in the best interest of shareholders. The Board continues to evaluate a number of opportunities in accordance with these criteria.

CORPORATE

Corporate Governance

Corporate governance remains a priority and the Company is committed to its programme of Board refreshment. The Directors will continue to review the balance and effectiveness of the Board with a view to adding independent non-executives commensurate with the nature and size of the Group's business.

Non-Executive Directors

In January 2017, Dr. Mike Watts stood down as an independent Non-Executive Director. Rob Gray, the Board's Senior Independent Director, replaced Dr. Mike Watts as Chairman of the Audit & Risk Committee. In December 2017, Rob Gray was appointed as Deputy Chairman of the Company, while remaining as Senior Independent Director, Chairman of the Audit & Risk Committee and member of the Remuneration and Nominations Committees.

Executive Directors

In February 2017, Jann Brown and Dr. Mike Watts joined the Company as full-time executives to co-head the Company's newly formed business development group and on 12 November 2017 were appointed as

Executive Directors. Both Jann and Mike were executive directors at Cairn Energy during its rapid growth to become a FTSE 100 company.

Roger Cagle and Cynthia Cagle stepped down as Executive Directors on 12 November 2017 and will retire as employees of the Group as of 11 September 2018 after over 20 years of service. They have each played a crucial role in the success of the business throughout that time. We would like to thank Cynthia and Roger for their immense contribution to SOCO, it has been a privilege to work with them and we wish them all the very best for the future.

OUTLOOK

Since inception SOCO has been committed to shareholder value creation through the growth of the business and cash returns to shareholders. In line with this, the Board proposes an increased final dividend for 2017 of 5.25 pence per share.

Capital expenditure for 2018 is budgeted at approx. $40m. The 2018 Vietnam work programme includes modification works on the FPSO and infill drilling of 2/3 wells on the TGT field and one well on the CNV field. Production guidance for 2018 is set at a net average 8,000 to 9,000 BOEPD. $6.0m of the capital expenditure is allocated for the purchase, processing and interpretation of seismic data on Blocks 125 & 126.

SOCO differentiates itself amongst its peers by having a consistently strong balance sheet, steady cash flows and low operating costs. This gives us a strong and stable foundation from which to grow the business. Annual cash returns to shareholders have been delivered since 2006 and sustaining these is an objective the Board expects to maintain in the future.

SOCO is strongly focused, reenergised and committed to the organic and inorganic growth of the business. It will continue to seek opportunities of scale, that will complement our existing high quality producing assets, and diversify the portfolio. We aim to build a business focused on sustainable cash flow generation, maximising value creation and total shareholder return. We will only purse opportunities that aim to fit our strategic, financial and operational criteria. We have a strong platform for growth in 2018 and beyond. We look forward to driving the strategy, with a focus on business growth, this year and beyond.

Rui de Sousa
Chairman

Ed Story
President and Chief Executive Officer

REVIEW OF OPERATIONS

VIETNAM

In Vietnam, Blocks 16-1 and 9-2, which comprise the TGT and CNV fields respectively, are located in shallow water in the hydrocarbon rich Cuu Long Basin, near the Bach Ho field, the largest field in the region which has produced more than one billion barrels of oil equivalent. The Blocks are operated through non-profit joint operating companies in which each partner holds an interest equivalent to its share in the respective Petroleum Contract. The Group holds a 30.5% working interest in Block 16-1 and a 25% working interest in Block 9-2 and its partners in both blocks are PetroVietnam Exploration and Production, a subsidiary of the national oil company of Vietnam, and PTTEP, the national oil company of Thailand.

Production summary

The Group's producing assets comprise its interests in the TGT and CNV fields. Total production from these fields averaged 28,506 BOEPD gross (2016: 33,861 BOEPD) and 8,276 BOEPD net to SOCO's working interest (2016: 9,883 BOEPD). TGT gross production averaged 22,300 BOEPD and 6,724 BOEPD net to SOCO's working interest in 2017 (2016: 27,650 BOEPD gross and 8,330 BOEPD net). CNV gross production averaged 6,206 BOEPD and 1,552 BOEPD net to SOCO's working interest in 2017 (2016: 6,211 BOEPD gross and 1,553 BOEPD net).

The average realised crude oil price for 2017 was approximately $56 per bbl, a premium to Brent of over $2 per bbl.

Production by field	FY 2017	FY 2016
TGT Production	**6,724**	**8,330**
Oil	6,299	7,825
Gas[1]	425	505
CNV Production	**1,552**	**1,553**
Oil	1,037	1,076
Gas[1]	515	477
Total Production	**8,276**	**9,883**
Oil	7,336	8,901
Gas[1]	940	982

Figures in BOEPD
[1] *Assumes oil equivalent conversion factor of 6,000 standard cubic feet per barrel of oil equivalent.*

Block 16-1 – TGT Field

(30.5% working interest; operated HLJOC)

The TGT field is located in the north eastern part of Block 16-1 offshore Vietnam and is operated by HLJOC. SOCO signed the PSC in December 1999 and the first commercial discovery was made in 2005.

TGT is a simple structure, with complex production intervals, extending over 16km and with hydrocarbons located in at least five major fault blocks. The producing reservoir is comprised of a complex series of over 80 modelled clastic reservoir intervals of Miocene and Oligocene age. Each interval requires individual reservoir management to optimise field recovery. The TGT field has been a rewarding investment for SOCO, with its attractive fiscal terms and low operating costs.

The first platform, H1-WHP, came on stream in August 2011, followed by the H4-WHP in July 2012. Crude oil from TGT is transported via subsea pipeline to the FPSO, where it is processed, stored and exported by tankers to regional oil refineries. Gas produced from the field is transported by pipeline to the nearby Bach Ho facilities for processing and onward transportation to shore by pipeline to supply the Vietnamese domestic market.

Updated Full Field Development Plan

Formal approval of the updated TGT FFDP was received from the Vietnamese Government in February 2017. Drilling operations on the TGT field resumed in Q1 2017,drilling two additional infill wells. The jack-up drilling rig, PetroVietnam Drilling VI, spudded the TGT-30P well on 8 March 2017, targeting the Miocene and Oligocene reservoir horizons in the crestal part of the H1.1 fault block. TGT-30P came on-line producing approximately 2,500 BOEPD with an as-expected 40% water cut.

On completion of TGT-30P, the rig moved to the H5-WHP in the southern part of the TGT field to drill the TGT–29P infill well. The well utilised smart completion technology to optimise hydrocarbons recovery. The TGT–29P well was tied into the production system in June 2017, after being completed on time and within budget, and came on-line producing at approximately 1,600 BOEPD.

The third and final drilling operation in the 2017 TGT Development Drilling Programme was the resumption of the TGT-14X step-out appraisal well on the H5 south fault block, initially spudded in 2015. The high angle and long reach of the well added complexity to drilling operations. The well was successfully drilled to the target depth; however, poor hole conditions prevented successful completion of the well. Smaller, non-standard drilling equipment will be required to re-drill the reservoir section of the well and, consequently, completion of drilling was deferred to the next campaign. Suspending the well meant it overran the budget and, costs for returning and completing the well have been included in the 2018 budget.

TGT – Production optimisation

Construction and installation of new processing equipment on the H1-WHP has been completed. The start-up of the water handling system on H1-WHP experienced setbacks and delays due to issues resulting from damaged valves and production stabilisation issues. However, the system is now functioning in line with expectations and production guidance has been achieved. The processing equipment will be designed to handle an additional 90,000 BLPD with specific water handling capacity of up to 65,000 BWPD. The increase in the total system handling capacity to approximately 180,000 BLPD allows for higher levels of oil production at the same or higher water cut rate than previously possible.

Following installation, the operator identified a sub-optimal performance issue affecting two gas compressors on the FPSO. Evaluation of the technical solutions and requirements for further investment in the gas compression issues is ongoing and these costs will be included in the 2018 work programme and budget.

Block 9-2 – CNV Field

(25% working interest; HVJOC)

The CNV field is located in the western part of Block 9-2, offshore southern Vietnam and is operated by the HVJOC. In contrast to the geology of TGT, the CNV field reservoir is fractured granitic basement which produces highly volatile oil with a high gas to oil ratio. Exploitation is dependent on the fracture interconnectivity to deplete the reservoir efficiently. Accordingly, traditional reservoir properties and STOIIP calculations are not straightforward. Hydrocarbons produced from CNV are transported via subsea pipeline to the BHCPP, where wet gas is separated from oil and transported via pipeline to an onshore gas facility for further distribution. The crude oil is stored on a floating, storage and offloading vessel prior to sale.

CNV - Production and optimisation

The CNV field has performed steadily throughout the year. CNV production averaged 6,206 BOEPD gross and 1,552 BOEPD net to SOCO's working interest in 2017 (2016: 6,211 BOEPD gross and 1,553 BOEPD, respectively).

During the execution of the well conversion from injection to production on CNV-6PST1, wireline was left in the completion. Fishing operations during 1H 2017 to recover the stuck wireline were unsuccessful. Alternative operations to work over the well are being considered for execution in 2018, alongside a side-track to an existing well to enhance recovery from the field. Discussions with the Bach Ho owners are ongoing to establish the most effective means of enhancing performance through modifications at the reception terminal.

VIETNAM NEW VENTURES

A PSC for Blocks 125 & 126, offshore central Vietnam, between PetroVietnam, SOVICO Holdings and SOCO's wholly owned subsidiary SOCO Exploration (Vietnam) Limited, was formally signed in October 2017, under which the Group has acquired a 70% operated interest over the two blocks.

Blocks 125 & 126 are in moderate to deep waters in the Phu Khanh Basin, north of the Cuu Long Basin, and have multiple structural and stratigraphic plays observed on the available 2D seismic data. Interpretation of the available data indicates there is good potential for source, expulsion and migration of oil with numerous reservoir and seal intervals likely.

The Group's forecast capex for 2018 includes the purchase of existing seismic data, reprocessing and interpretation of seismic data, with a view to drilling the first exploration well potentially as early as 2020.

REPUBLIC OF CONGO (BRAZZAVILLE)

Lidongo, Loubana, Lideka and Viodo Prospect Areas, offshore Congo (Brazzaville)

(40.39% working interest; SOCO-operated)

The Group holds its interests in the former Marine XI contract area, located offshore Congo (Brazzaville) in the shallow water Lower Congo Basin, through an 85% owned Congolese subsidiary, SOCO Exploration and Production Congo SA. The area exists going forward as four distinct exploitation permits following the expiry of the exploration phase of the Marine XI PSC in March 2017. Loubana is located in the north west section of the former contract area, Lideka in the south west, Viodo in the centre and south east and Lidongo in the north east.

Activity in 2016 and 2017 focused on securing long term PEXs over each of the four prospect areas beyond the expiry of the exploration phase of the PSC. The PEX over the Lidongo prospect area commenced in October 2016 and has a duration of 20 years. Discussions with the authorities and the Marine XII partners on commercialisation of Lidongo continue. In Q1 2017, SOCO submitted three further PEX applications over the remaining prospect areas, Loubana, Lideka and Viodo. Each of these PEXs has now been awarded with a 25-year duration, effective from 28 December 2017.

ANGOLA

Cabinda North Block

(22% working interest, Non-operated)*

SOCO's 85% owned subsidiary, SOCO Cabinda Limited, holds a 22% working interest in the PSC for the Cabinda North Block, onshore the Angolan Cabinda enclave. Following discussions amongst the partners and the

Angolan authorities to agree a change of operatorship and a reassignment of interests amongst the block partners, SOCO has agreed to increase its non-operating working interest in the Cabinda North PSC from 17% to 22% pursuant to the same series of transactions that will involve assumption of operatorship by Eni. The legal documents to complete the changes were signed by the contractor parties in November 2017. Final details and timing of the formal governmental Executive Decree to approve the change of operator and the reassignment of interests are expected shortly.

* Pending formal government approval; paying interest 27.5% pending formal government approval taking into account Sonangol exploration carry under Cabinda North joint operating agreement. Current SOCO working interest 17% and paying interest 21.25%.

GROUP RESERVES AND CONTINGENT RESOURCES

An independent audit of management estimates of Reserves and Contingent Resources for TGT and CNV, as of 1 October 2017, was completed by Senergy International Sdn Bhd as part of Lloyd's Register Group Limited ("LR Senergy") in January 2018.

TGT Reserves and Contingent Resources

The October 2017 TGT estimated Reserves were based on the current producing wells and scope of the wells being considered for approval to be drilled in 2018 at end-September 2017, with consideration given to a small number of additional likely near-term wells in 2019, optimal field management and the increased liquid handling capacity at the H1-WHP. The 2017 TGT estimated Reserves do not take into account the fully approved programme in the updated FFDP. This conservative approach will be reviewed following the interpretation and incorporation of the results of the 2018 infill drilling programme into the static and dynamic models. All volumes beyond the approved scope outlined above were classified as Contingent Resources.

The range of Reserves and Contingent Resources volumes continue to capture management's view of the full potential of the TGT field. The estimates are grounded in the results of the revised ERCE Dynamic Simulation Model and the current field performance and reflect the degree of uncertainty around the oil-in-place estimates.

The initial ERCE static and dynamic models, developed in 2013-14, have been updated and matched with the additional production from the field. With the approved updated FFDP which includes a significant upgrade to the fluid processing capacity of the H1 platform, and the anticipated 2018 drilling campaign, after subtracting production during 2017, there is only a minor revision to the Reserves compared to year-end 2016.

TGT Field Oil-In-Place Estimates (MMbbl)			
	P90	P50	P10
Stock Tank Oil Initially In Place	376	585	880

TGT Field Estimated Ultimate Recovery			
Reserves + Production	**1P**	**2P**	**3P**
Oil[1]	126.5	147.7	165.9
Gas[2]	7.6	8.9	10.4
Total	134.1	156.6	176.3
Contingent Resources	**1C**	**2C**	**3C**
Oil	25.0	40.6	56.1
Gas[2]	4.7	8.5	12.5
Total	29.7	49.1	68.6
Total Ultimate Recovery			
Oil	151.5	188.3	222.0
Gas[2]	12.3	17.4	22.9
Total	163.8	205.7	244.9

Figures in MMboe

[1] Volumes include previously produced oil and gas plus estimated remaining recoverable hydrocarbons.
[2] Assumes oil equivalent conversion factor of 6,000 standard cubic feet per barrel of oil equivalent.
[3] This table has been derived by SOCO from the audited figures.

SOCO Working Interest Reserves and Resources TGT Field at 31 December 2017			
Reserves[1]	**1P**	**2P**	**3P**
Oil	15.5	21.8	27.3
Gas[2]	0.9	1.3	1.7
Total	16.4	23.1	29.0
Contingent Resources	**1C**	**2C**	**3C**
Oil	7.5	12.3	16.9
Gas[2]	1.4	2.6	3.8
Total	8.9	14.9	20.7
Sum of Reserves and Contingent Resources[3, 4]	**1P & 1C**	**2P & 2C**	**3P & 3C**
Oil	23.0	34.1	44.2
Gas[2]	2.3	3.9	5.5
Total	25.3	38.0	49.7

Figures in MMboe

[1] This table has been derived by the Company by deducting the produced volumes between 1 October 2017 to 31 December 2017 inclusive from the LR Senergy audited figures.
[2] Assumes oil equivalent conversion factor of 6,000 standard cubic feet per barrel of oil equivalent.
[3] The summation of Reserves and Contingent Resources has been prepared by the Company.
[4] *Contingent Resources are subject to Chance of Commercialisation estimated by LR Senergy at 70%.*

CNV Reserves and Contingent Resources

Re-evaluation of the field performance dynamics has led to the HVJOC partners ceasing water injection and agreeing to convert the CNV-6P-ST1 injection well to production. This change to the drive mechanism from "bottom-up" water drive to "top-down" gas drive, due to the volatile nature of the oil, will liberate gas in the well bore. This gas will rise to the crest of the reservoir, expanding and therefore displacing oil into the wells. Extensive simulation has demonstrated the benefit of this approach.

Reserves relate to the current producing wells. Contingent Resources comprise the estimated recoverable volumes from additional wells and/or sidetracks to existing wells.

SOCO Working Interest Reserves and Contingent Resources CNV Field at 31 December 2017			
Reserves[1]	**1P**	**2P**	**3P**
Oil	2.6	3.4	4.3
Gas[2]	1.2	1.6	2.0
Total	3.8	5.0	6.3
Contingent Resources	**1C**	**2C**	**3C**
Oil	2.7	4.0	5.3
Gas[2]	1.2	1.9	2.5
Total	3.9	5.9	7.8
Sum of Reserves and Contingent Resources[3, 4]	**1P & 1C**	**2P & 2C**	**3P & 3C**
Oil	5.3	7.4	9.6
Gas[2]	2.4	3.5	4.5
Total	7.7	10.9	14.1

Figures in MMboe

[1] This table has been derived by the Company by deducting the produced volumes between 1 October 2017 to 31 December 2017 inclusive from the LR Senergy audited figures.
[2] Assumes oil equivalent conversion factor of 6,000 standard cubic feet per barrel of oil equivalent.
[3] The summation of Reserves and Contingent Resources has been prepared by the Company
[4] Contingent Resources are subject to Chance of Commercialisation estimated by LR Senergy at 70%.

FINANCIAL REVIEW

FINANCE STRATEGY

Our finance strategy underpins the Group's business model and goes hand in hand with our core business strategy of building shareholder value through our oil and gas portfolio.

The finance strategy is founded on three core areas of focus – capital discipline, capital allocation and capital return.

During 2017, we generated cash flow from our operations in Vietnam of $87.8m (2016: $85.6m) and also recovered $42.7m, the final amount due following the 2005 sale of our Mongolia interests.

We have a low cost asset base, a robust cash balance and a balance sheet with the capacity to support debt for the right projects.

The Group is positioned for growth and during 2017 increased its business development activities. Our pursuit for growth opportunities will always be positioned within our long standing core strategy of building value for shareholders.

Change of Accounting Policy to successful efforts

During the year, we carried out a full review of our accounting policies, in accordance with best practice, to ensure that the policies we use remain fit for purpose for the next phase of the business. As a result of that review, we have changed our policy on accounting for Exploration and Evaluation assets.

Since the introduction of IFRS in 2005, we have used a modified full cost basis of accounting often associated with companies whose focus is on exploration. Under this policy, we assessed E&E assets for impairment on a geographical cost pooling (typically licence by licence basis). We have now changed our policy to successful efforts under which E&E assets are assessed on a more granular well by well basis. This change in policy reflects the maturity of the business and is used by the majority of our UK listed E&P peer group. Prior year figures have been restated on a successful efforts basis, resulting in a decrease in 31 December 2016 net assets of $185.3m (refer to note 2).

The impact of this change on the current year income statement (other than the changes arising on our African assets, explained below) is to reduce the DD&A charge by $12.7m; and to reduce the deferred tax asset by $1.8m. Both of these changes are a result of the lower cost base held in the balance sheet for the assets in Vietnam, as certain historic E&E costs have now been fully written off as part of the restatement of prior year balances.

Strategic Review - African Assets

As announced in our January trading statement, during 2017 we reviewed our strategic priorities and the Board decided that the African assets, Marine XI (now the Lidongo, Lideka, Loubana and Viodo exploitation permits) and Cabinda North, are no longer a core priority for the Group. Minimal capital will be spent on them in the near future and the associated work programme commitments reflect this position. There has been no change in our assessment of the potential of these assets; however, in the absence of a near term work programme and investment, it is no longer appropriate to carry the costs previously incurred on these assets in the balance sheet. They have therefore been fully impaired.

If no change to our accounting policies had been made, these assets would still have been fully impaired and the resulting impairment charge in the year would have been $219.9m. However, the interaction with the change of policy to successful efforts means that $67.6m of this cost has been recorded through the restatement of prior year balances. The actual charge for the year is therefore $152.3m.

Both of these changes - the move to a successful efforts accounting policy and the impairment of the African assets following the strategic review - are explained in full in notes 2a and 6 to the Financial Information.

OPERATING PERFORMANCE

The Group continued to deliver robust revenue of $156.2m (2016: $154.6m). The slight increase year on year is the result of the higher average realised crude oil price of $56.43/bbl (2016: $45.01/bbl), over $2/bbl premium to Brent, offset by a 16.3% decline in production levels from 9,883 BOEPD to 8,276 BOEPD.

Cash operating costs decreased to $41.5m (2016: $42.3m).

Cash operating costs per barrel

	2017	(Restated) 2016
	$m	$m
Cost of sales	**115.0**	119.9
Less:		
Depreciation, depletion and amortisation	**(56.5)**	(64.7)
Production based taxes	**(13.6)**	(13.4)
Inventories	**(1.5)**	2.6
Other cost of sales	**(1.9)**	(2.1)
Cash operating costs	**41.5**	42.3
Production (BOEPD)	**8,276**	9,883
Cash operating cost per BOE ($)	**13.73**	11.70

DD&A per barrel

	2017	(Restated) 2016
	$m	$m
Depreciation, depletion and amortisation	**56.5**	64.7
Production (BOEPD)	**8,276**	9,883
DD&A per BOE ($)	**18.72**	17.89

*See note 12 for details

The per barrel cost of both cash operating cost and DD&A have increased due to the allocation of fixed cost over a reduced number of barrels produced in 2017. Prior to the impact of the change in policy to successful efforts, the Group DD&A rate for 2017 was $22.91/boe. The retrospective write off of certain exploration costs from the balance sheet has reduced this by 18.5% to $18.72/boe. This reduction in rates will apply to future periods and, whilst there is no cash impact, it will feature positively in the Income Statement.

General and administrative expenses of $18.3m (2016: $13.5m) includes $4.7m (2016: $1.7m) incurred on M&A activity, leaving underlying G&A expenses of $13.6m (2016: $11.8m) charged to the income statement. This increase is a result of the transition of the executive team, in the handover from the outgoing to the incoming directors.

Taxation

The tax expense during the year increased 6%, from $26.1m (restated) for 2016 to $27.7m in 2017. This increase reflects the higher operating profit for the year prior to exploration expense. The Group's effective tax rate approximates to the statutory tax rate in Vietnam of 50%, after excluding the effect of the $152.3m exploration write off as well as additional non-deductible expenses and unrecognised tax losses (see note 4 of the Financial Information).

Loss for the year

The Group made a loss during the year of $157.3m (2016: $4.2m restated), including E&E write offs of $152.3m (2016: $2.2m write back restated). The loss prior to E&E impact was $5.0m (2016: $6.4m restated).

CASH FLOW

Operating cash flow of $45.0m (2016: $46.0m) was generated from our assets in Vietnam.

Capital Cash Expenditure

Total cash capital expenditure for the year, including abandonment, was $29.3m (2016: $40.1m). $23.9m was spent on recommencing the drilling campaign on TGT, funding abandonment commitments and upgrading infrastructure, all in Vietnam. On the intangible assets $0.9m relates to the award of the new PSC in Vietnam over Blocks 125 & 126 and $4.5m was spent on the assets in Africa.

Tax strategy and total tax contribution

Tax is managed proactively and responsibly with the goal of ensuring that the Group is compliant in the countries in which it holds interests. Any tax planning undertaken is commercially driven and within the spirit as well as the letter of the law. This approach forms an integral part of SOCO's sustainable business model.

The Group's Code of Business Conduct & Ethics seeks to build open, cooperative and constructive relationships with tax authorities and governmental bodies in all territories in which it operates. The Group supports greater transparency in tax reporting to build and maintain stakeholder trust.

During 2017, the total payments to governments for the Group amounted to $182.1m, of which $176.4m or 97% was related to the Vietnam producing licence areas, of which $117.8m was for indirect taxes based on production entitlement. The breakdown of the contributions, including payroll taxes and other taxes will be contained within the additional information in the 2017 Annual Report & Accounts.

BALANCE SHEET

Intangible assets decreased during the period to $3.8m (2016: $150.6m (restated)) almost exclusively due to the full impairment of the African assets of $152.3m. During the period $5.5m was added, $1.5m on the newly awarded Blocks 125 & 126 in Vietnam and $4.0m on Africa which was subsequently impaired.

Property, plant and equipment decreased by $48.3m from $554.2m (restated) to $505.9m.

This is made up of:-

Investments in assets	$20.4m
Less:	
Downward revision to decommissioning asset	$11.8m
DD&A	$56.9m
Total	$48.3m

There are no impairments to the Group's producing assets.

Cash and cash equivalents, including liquid investments, increased by 37.3% to $137.7m (2016: $100.3m).

The $42.7m due on the 2005 sale of our interests in Mongolia, held at 31 December 2016 as a financial asset, was received during the year in full.

Trade and other receivables decreased to $20.7m (2016: $24.7m) largely due to the timing of crude oil cargos.

Trade and other payables increased slightly to $23.1m (2016: $22.4m) as a result of increased M&A activity over the year end.

OWN SHARES

The SOCO EBT holds ordinary shares of the Company for the purposes of satisfying long term incentive awards for senior management. At the end of 2017, the Trust held 2,114,596 (2016: 2,299,767) Shares, representing 0.64% (2016: 0.67%) of the issued share capital..

In addition, as at 31 December 2017, the Company held 9,122,268 (2016: 9,122,268) treasury shares, representing 2.67% (2016: 2.67%) of the issued share capital.

GOING CONCERN

SOCO regularly monitors its business activities, financial position, cash flows and liquidity. Scenarios and sensitivities are included in the forecasts, including changes in commodity prices and in production levels from the assets in Vietnam, plus other factors which could affect the Group's future performance and position.

These forecasts show that the Group will have sufficient financial headroom for the twelve months from the date of approval of the 2017 Accounts. Based on this analysis, the Directors have a reasonable expectation that that the Group has adequate resources to continue in operational existence for the foreseeable future. Therefore, they continue to use the going concern basis of accounting in preparing the annual Financial Statements.

ANNUAL DIVIDEND & COMPANY DISTRIBUTABLE RESERVES

SOCO remains committed to paying an annual dividend. During the year the Company paid a dividend to shareholders of 5 pence per Ordinary Share (2016: 4 pence), at a cost to the company of $21.0m (2016: $17.5m).

In 2017, the change in accounting policy for E&E assets and the write down of the African assets, positions the balance sheet well for the future. The lower carrying cost of our asset base has reduced the depletion and tax charges this year and the positive impact will also be felt in future years. After taking account of the results for the year, the company currently has distributable reserves of over $157m, which provides cover for dividends in line with the proposal for 2017 of approximately 8 years.

The Directors are recommending a final dividend of 5.25 pence per Ordinary Share, subject to approval at the AGM on 7 June 2018.

FINANCIAL OUTLOOK

SOCO's financial strength is founded on our long term approach to managing capital.

Capital discipline focuses on controlling and managing costs. Capital investment and divestment decisions are taken to allocate capital where it will provide risk adjusted full cycle returns. It is this approach that has allowed us to return significant amounts of capital to shareholders. In future, we look to add another strand to the story – capital growth – to underpin the sustainability of the dividends over the longer term.

INDEPENDENT AUDITOR'S REPORT TO THE SHAREHOLDERS OF SOCO INTERNATIONAL PLC ON THE PRELIMINARY ANNOUNCEMENT OF SOCO INTERNATIONAL PLC

As the independent auditor of SOCO International PLC we are required by UK Listing Rule LR 9.7A.1(2)R to agree to the publication of SOCO International PLC's preliminary announcement statement of annual results for the year ended 31 December 2017.

The preliminary statement of annual results for the year ended 31 December 2017 includes the 2017 preliminary results, chairman and chief executive officer's statement, review of operations, financial review, the consolidated income statement, the consolidated and parent company balance sheets, the consolidated and parent company statements of changes in equity, the consolidated and parent company cash flow statements, the related notes 1 to 12 and the glossary of terms.

The directors of SOCO International PLC are responsible for the preparation, presentation and publication of the preliminary statement of annual results in accordance with the UK Listing Rules.

We are responsible for agreeing to the publication of the preliminary statement of annual results, having regard to the Financial Reporting Council's Bulletin "The Auditor's Association with Preliminary Announcements made in accordance with UK Listing Rules".

STATUS OF OUR AUDIT OF THE FINANCIAL STATEMENTS

Our audit of the annual financial statements of SOCO International PLC is complete and we signed our auditor's report on 21 March 2018. Our auditor's report is not modified and contains no emphasis of matter paragraph.

Our audit report on the full financial statements sets out the following key audit matters which had the greatest effect on our overall audit strategy; the allocation of resources in our audit; and directing the efforts of the engagement team, together with how our audit responded to those key audit matters and the key observations arising from our work:

Change in Exploration & Evaluation ("E&E") Accounting Policy	
Key audit matter description	During the year management have voluntarily elected to change the unit of account (cash generating unit) applied in assessing their E&E assets for impairment under IFRS 6 *Exploration for and Evaluation of Mineral Resources*. In previous periods they assessed E&E assets for impairment on a geographical cost pool basis, which in practice was applied at the licence level. In the current year, management has changed the unit of account such that impairment is now assessed on a well-by-well basis. This represents a change in accounting policy and has therefore resulted in a restatement of the group's prior year results, including a reduction in net assets at 1 January 2016 of $199.4 million, as disclosed in note 2(a). Under IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors*, voluntary changes in accounting policy can only be made if they result in more relevant and reliable information about the effect of transactions on an entity's financial position. We have identified a key audit matter associated with the appropriateness of the change in accounting policy as well as the accuracy and completeness of the resulting restatement of prior year balances and related disclosures.

	Further details of this matter are provided in note 2(a) of the financial information.
How the scope of our audit responded to the key audit matter	Our procedures included: • understanding the basis for management's conclusion that the change in accounting policy resulted in more relevant and reliable information about the entity's financial position; this assessment took into account our knowledge of the industry as well as a comparison of the revised unit of account with reference to a selection of the company's peer group; • assessing the process applied by management to calculate the impact of the change in accounting policy on prior periods; • validating the accuracy and completeness of the restatement of prior period balances; this included obtaining a supporting schedule of adjustments from Management and verifying key inputs to appropriate supporting evidence, including past annual reports, press releases, joint operator reports and evidence obtained in prior year audits; and • assessing the completeness and accuracy of the associated disclosure for compliance with IAS 8.
Key observations	We are satisfied that management's revised policy is in accordance with the principles of IAS 8 and that the related impact on prior period balances has been appropriately calculated and disclosed.
Impairment of Producing Oil & Gas Assets	
Key audit matter description	The value of property, plant and equipment relating to the Group's producing oil and gas assets as at 31 December 2017 was $505.4 million (2016 restated: $553.6 million). This is considered a key audit matter due to the significant judgements and estimates involved in assessing whether any impairment, or impairment reversal, has arisen at year-end, and in quantifying any such impairments or reversals. Given the importance of producing assets to the Group and the judgemental nature of the inputs used in determining the recoverable amounts, we also considered there to be a fraud risk in this area. Management reviewed both of its producing fields in Vietnam for indicators of impairment, with no indicators identified for Te Giac Trang ('TGT') but an indicator identified in relation to Ca Ngu Vang ('CNV'), primarily due to a reduction in reserves. Management has estimated the fair values less costs of disposal of each field and compared these to the carrying amount of each field on the balance sheet. For TGT whilst Management concluded there were no impairment indicators, the recoverable value was nonetheless

	calculated to demonstrate the existence of significant available headroom. Management's fair value estimate is based on key assumptions which include: • oil and gas prices; • reserves estimates and production profiles; • the incremental value of contingent resources for CNV; and • the discount rate adopted, which was unchanged for TGT at 10% but for CNV was reduced from 12.5% to 10%. The carrying value of property, plant and equipment is considered by management as a critical accounting judgement and key source of estimation uncertainty. No impairment charges or impairment reversals were recorded during the year. Further details of the key assumptions used by management in their impairment evaluation are provided in note 7 of the financial information.
How the scope of our audit responded to the key audit matter	As well as our work on reserves as noted below; • we understood the basis for management's conclusion as to the existence or otherwise of impairment triggers for TGT and CNV; • we compared oil and gas price assumptions with third party forecasts and publicly available forward curves; • we understood the basis for management's decision to reduce the CNV discount rate to 10% and used our internal valuation specialists to perform an independent recalculation of the discount rates used for both TGT and CNV; • we assessed management's other assumptions by reference to third party information, our knowledge of the group and industry and also budgeted and forecast performance; • we tested management's impairment calculations for mechanical accuracy; • we considered whether the incremental value attributed to contingent resource estimates for CNV was appropriate; • we completed a scenario analysis for CNV, through which we conducted sensitivities for a range of input assumptions, including oil price and discount rates, and computed what we believed to be a reasonable range of recoverable amounts for CNV, and then compared the carrying value of CNV against this range; and • we considered whether management's disclosures relating to impairment and associated estimation uncertainty were adequate.

Key observations	We are satisfied that there were no indicators of impairment for TGT. For CNV we are satisfied that, based on the scenario analysis outlined above, neither an additional impairment charge nor an impairment reversal are required and that the related disclosures in note 7 of the financial information are appropriate.
Impairment of Intangible Exploration & Evaluation Assets	
Key audit matter description	The total value of E&E assets as at 31 December 2017 held by the Group was \$3.8 million (2016 restated: \$150.6 million), after recording an impairment of \$152.3 million. The Group's principal E&E interests, being the Marine XI licence in the Republic of Congo (Brazzaville) and the Cabinda licence in Angola, were both impaired in full during the year. The remaining capitalised exploration balance as at 31 December 2017 relates to Blocks 125 & 126 in Vietnam. In accordance with relevant accounting standards, E&E assets are assessed for impairment at least annually. This is considered a key audit matter due to the significant judgments that are required and the material carrying values of E&E assets that were previously recorded in the financial statements. These judgements include the effect of the significant and prolonged fall in oil price on the viability of the Group's E&E projects. Management assesses whether there were any indicators of impairment of the Group's E&E assets by reference to IFRS 6 *Exploration for and evaluation of mineral resources*, such as; • expiry or relinquishment of exploration and evaluation licences; • substantive expenditure for further exploration and evaluation in the specific area is neither budgeted nor planned; • whether exploration and evaluation activities have not led to the

	discovery of commercially viable quantities of mineral resources and the entity has decided to discontinue activities in the area; or • whether data exists to suggest that the carrying amount of the E&E asset is unlikely to be recovered in full from successful development or by sale. The carrying value of E&E assets is considered by management as a critical accounting judgement and key source of estimation uncertainty. The current status of the Marine XI and Cabinda licences together with activity during the year is summarised in the review of operations. As outlined in the financial review, in January 2018 the company announced that following a review of its strategic priorities the directors had decided that its African E&E asset portfolio was no longer a core priority for the group, with minimal capital due to be spent on the related assets in the near future. Therefore these assets were fully impaired in the 2017 financial year. Further details of the group's E&E assets and the related impairment judgements are given in note 6 of the financial information.
How the scope of our audit responded to the key audit matter	Our procedures were focused on challenging management's conclusions that the Marine XI and Cabinda licences should be impaired in full. This included: • participating in meetings with key operational and finance staff to understand the future intention for each asset; • confirming that substantive expenditure for these assets is neither budgeted nor planned; • understanding the basis for management's conclusion that there is currently limited ability to realise value from these assets; this included understanding the extent to which material value was attributed to these licences during recent New Business discussions.
Key observations	Management do still plan on conducting some limited work in future periods on these assets, primarily to retain legal title and hence enable them to continue marketing these assets for disposal. However, based on information gathered through recent New Business discussions, there is no reliable evidence that the group will be able to realise material value from these assets. Accordingly, also taking into consideration that these assets are no longer a core priority, we are satisfied that the full impairment of the Marine XI and Cabinda E&E assets in the current year is appropriate.

Oil & Gas Reserves and Contingent Resource Estimates	
Key audit matter description	This was considered to be a key audit matter due to the subjective nature of reserves and contingent resource estimates, their impact on the Financial Statements as key inputs within the assessment of impairment and the depreciation, depletion and amortisation ('DD&A') calculations, and because both the TGT and CNV fields are complex fields contributing all of the value of the Group's recognised reserves. Management has engaged a third party reservoir engineering expert to provide an independent report on the Group's reserves and contingent resource estimates using standard industry reserve estimation methods and definitions for both the CNV and TGT fields. Management's reserves and contingent resource estimates are included in the review of operations. In addition, management has explained the scope of work of the third party expert and their findings in the review of operations.
How the scope of our audit responded to the key audit matter	For both TGT and CNV assets: • we understood the process used by management to derive their estimates of reserves and contingent resources and how they provide information to, and interact with, the third party expert; • we reviewed the third party expert's report on SOCO's reserves and contingent resource estimates as summarised in the review of operations and checked that these estimates were used consistently throughout the accounting calculations reflected in the financial information; and • we communicated directly with the third party experts to discuss and assess their scope of work, expertise and objectivity.
Key observations	We are satisfied that the reserves and contingent resources figures used by SOCO in the group's DD&A and impairment calculations are appropriate and consistent with those reported by the third party experts.

These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we did not provide a separate opinion on these matters.

PROCEDURES PERFORMED TO AGREE TO THE PRELIMINARY ANNOUNCEMENT OF ANNUAL RESULTS

In order to agree to the publication of the preliminary announcement of annual results of SOCO International PLC we carried out the following procedures:

(a) checked that the figures in the preliminary announcement covering the full year have been accurately extracted from the audited financial statements and reflect the presentation to be adopted in the audited financial statements;

(b) considered whether the information (including the management commentary) is consistent with other expected contents of the annual report;

(c) considered whether the financial information in the preliminary announcement is misstated;

(d) considered whether the preliminary announcement includes a statement by directors as required by section 435 of CA 2006 and whether the preliminary announcement includes the minimum information required by UKLA Listing Rule 9.7A.1;

(e) where the preliminary announcement includes alternative performance measures ("APMs"), considered whether appropriate prominence is given to statutory financial information and whether:

- the use, relevance and reliability of APMs has been explained;
- the APMs used have been clearly defined, and have been given meaningful labels reflecting their content and basis of calculation;
- the APMs have been reconciled to the most directly reconcilable line item, subtotal or total presented in the financial statements of the corresponding period; and
- comparatives have been included, and where the basis of calculation has changed over time this is explained.

(f) read the management commentary and any other narrative disclosures and considered whether they are fair, balanced and understandable.

USE OF OUR REPORT

Our liability for this report, and for our full audit report on the financial statements is to the company's members as a body, in accordance with Chapter 3 of Part 16 of the Companies Act 2006. Our audit work has been undertaken so that we might state to the company's members those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company and the company's members as a body, for our audit work, for our audit report or this report, or for the opinions we have formed.

David Paterson ACA (Senior statutory auditor)

For and on behalf of Deloitte LLP

Statutory Auditor

London, United Kingdom

21 March 2018

Consolidated Income Statement

for the year to 31 December 2017

	Notes	2017 $ million	(Restated)[1] 2016 $ million
Revenue	3	**156.2**	154.6
Cost of sales		**(115.0)**	(119.9)
Gross profit		**41.2**	34.7
Administrative expenses		**(18.3)**	(13.5)
Exploration (expense) write back	6	**(152.3)**	2.2
Operating (loss) profit		**(129.4)**	23.4
Investment revenue		**1.4**	0.5
Finance costs		**(1.6)**	(2.0)
(Loss) profit before tax	3	**(129.6)**	21.9
Tax	3,4	**(27.7)**	(26.1)
Loss for the year		**(157.3)**	(4.2)
Loss per share (cents)			
Basic	5	**(47.7)**	(1.3)
Diluted	5	**(47.7)**	(1.3)

Consolidated Statement of Comprehensive Income

for the year to 31 December 2017

	2017 $ million	(Restated)[1] 2016 $ million
Loss for the year	**(157.3)**	(4.2)
Items that may be subsequently reclassified to profit or loss:		
Unrealised currency translation differences	**(0.4)**	(0.2)
Total comprehensive loss for the year	**(157.7)**	(4.4)

[1] In 2017, the Group changed its accounting policy for intangible exploration and evaluation assets and has adopted the successful efforts method of accounting. This change in accounting policy has been applied retrospectively and consolidated income statement, balance sheet and cash flow statement and related notes of the financial statements have been restated accordingly. Full details are provided in Note 2 (a).

Balance Sheets

as at 31 December 2017

			(Restated)	(Restated)		
				Group		**Company**
		2017	2016	As at 1 January 2016	**2017**	2016
	Notes	**$ million**	$ million	$ million	**$ million**	$ million
Non-current assets						
Intangible assets		**3.8**	150.6	142.8	**-**	-
Property, plant and equipment	7	**505.9**	554.2	609.0	**0.5**	0.6
Investments		**-**	-	-	**388.2**	530.6
Other receivables		**36.9**	33.8	29.5	**-**	-
		546.6	738.6	781.3	**388.7**	531.2
Current assets						
Inventories		**4.2**	5.7	3.1	**-**	-
Trade and other receivables		**20.7**	24.7	19.5	**0.7**	0.8
Tax receivables		**0.6**	0.7	0.7	**0.1**	0.3
Financial asset	8	**-**	42.7	52.7	**-**	-
Liquid investments		**25.3**	15.3	-	**-**	-
Cash and cash equivalents		**112.4**	85.0	103.6	**1.0**	0.5
		163.2	174.1	179.6	**1.8**	1.6
Total assets		**709.8**	912.7	960.9	**390.5**	532.8
Current liabilities						
Trade and other payables		**(23.1)**	(22.4)	(37.2)	**(9.6)**	(6.7)
Tax payable		**(6.8)**	(9.2)	(7.8)	**(0.2)**	(0.1)
		(29.9)	(31.6)	(45.0)	**(9.8)**	(6.8)
Net current assets (liabilities)		**133.3**	142.5	134.6	**(8.0)**	(5.2)
Non-current liabilities						
Deferred tax liabilities		**(132.6)**	(147.0)	(162.9)	**-**	-
Long term provisions		**(52.7)**	(62.9)	(59.9)	**-**	-
		(185.3)	(209.9)	(222.8)	**-**	**-**
Total liabilities		**(215.2)**	(241.5)	(267.8)	**(9.8)**	(6.8)
Net assets		**494.6**	671.2	693.1	**380.7**	526.0
Equity						
Share capital		**27.6**	27.6	27.6	**27.6**	27.6
Other reserves		**245.9**	243.8	242.3	**195.8**	194.5
Retained earnings		**221.1**	399.8	423.2	**157.3**	303.9
Total equity		**494.6**	671.2	693.1	**380.7**	526.0

Statements of Changes in Equity

for the year to 31 December 2017

				Group
	Called up share capital $ million	**Other reserves $ million**	**Retained earnings $ million**	**Total $ million**
As at 1 January 2016 (as previously reported)	27.6	242.3	622.6	892.5
Effect of change in accounting policy for intangible exploration and evaluation assets (Note 2 (a))	-	-	(199.4)	(199.4)
As restated	27.6	242.3	423.2	693.1
Loss for the year	-	-	(4.2)	(4.2)
Unrealised currency translation differences	-	(0.2)	(0.2)	(0.4)
Distributions	-	-	(17.5)	(17.5)
Share-based payments	-	0.2	-	0.2
Transfer relating to share-based payments	-	1.5	(1.5)	-
As at 1 January 2017	**27.6**	**243.8**	**399.8**	**671.2**
Loss for the year	**-**	**-**	**(157.3)**	**(157.3)**
Unrealised currency translation differences	**-**	**0.4**	**(0.4)**	**-**
Distributions	**-**	**-**	**(21.0)**	**(21.0)**
Share-based payments	**-**	**1.7**	**-**	**1.7**
As at 31 December 2017	**27.6**	**245.9**	**221.1**	**494.6**

				Company
	Called up share capital $ million	**Other reserves $ million**	**Retained earnings $ million**	**Total $ million**
As at 1 January 2016	27.6	195.3	412.6	635.5
Retained profit for the year	-	-	17.5	17.5
Unrealised currency translation differences	-	(0.2)	(107.2)	(107.4)
Distributions	-	-	(17.5)	(17.5)
Share-based payments	-	0.2	-	0.2
Transfer relating to share-based payments	-	(0.8)	(1.5)	(2.3)
As at 1 January 2017	**27.6**	**194.5**	**303.9**	**526.0**
Loss for the year	**-**	**-**	**(176.6)**	**(176.6)**
Unrealised currency translation differences	**-**	**0.4**	**51.0**	**51.4**
Distributions	**-**	**-**	**(21.0)**	**(21.0)**
Share-based payments	**-**	**1.7**	**-**	**1.7**
Transfer relating to share-based payments	**-**	**(0.8)**	**-**	**(0.8)**
As at 31 December 2017	**27.6**	**195.8**	**157.3**	**380.7**

Cash Flow Statements

for the year to 31 December 2017

		Group		Company	
		2017	2016	**2017**	2016
	Note	**$ million**	$ million	**$ million**	$ million
Net cash from (used in) operating activities	10	**45.0**	46.0	**(12.9)**	(7.9)
Investing activities					
Purchase of intangible assets		**(5.4)**	(27.4)	**-**	-
Purchase of property, plant and equipment		**(20.8)**	(8.4)	**(0.1)**	(0.1)
Increase in liquid investments [1]		**(10.0)**	(15.3)	**-**	-
Payment to abandonment fund		**(3.1)**	(4.3)	**-**	-
Deferred proceeds on disposal of Mongolia assets		**42.7**	10.0	**-**	-
Investment in subsidiary undertakings		**-**	-	**(3.1)**	(2.9)
Dividends received from subsidiary undertakings		**-**	-	**37.6**	30.0
Net cash from (used in) investing activities		**3.4**	(45.4)	**34.4**	27.0
Financing activities					
Share-based payments		**(0.3)**	(0.9)	**(0.3)**	(0.9)
Distributions	9	**(21.0)**	(17.5)	**(21.0)**	(17.5)
Net cash used in financing activities		**(21.3)**	(18.4)	**(21.3)**	(18.4)
Net increase (decrease) in cash and cash equivalents		**27.1**	(17.8)	**0.2**	0.7
Cash and cash equivalents at beginning of year		**85.0**	103.6	**0.5**	0.2
Effect of foreign exchange rate changes		**0.3**	(0.8)	**0.3**	(0.4)
Cash and cash equivalents at end of year [1]		**112.4**	85.0	**1.0**	0.5

[1] Liquid investments comprise short term liquid investments of between three to six months maturity while cash and cash equivalents comprise cash at bank and other short term highly liquid investments of less than three months maturity. The combined cash and cash equivalents and liquid investments balance at 31 December 2017 was $137.7 million (2016: $100.3 million).

Notes to the Consolidated Financial Information

1. General information

The financial information set out above does not constitute the Company's statutory accounts for the years ended 31 December 2017 or 2016, but is derived from those accounts. A copy of the statutory accounts for 2016 has been delivered to the Registrar of Companies and those for 2017 will be delivered following the Company's annual general meeting. The auditors have reported on those accounts; their reports were unqualified, did not draw attention to any matters by way of emphasis without qualifying their report and did not contain statements under section 498(2) or (3) of the Companies Act 2006. Whilst the financial information included in this preliminary announcement has been computed in accordance with International Financial Reporting Standards (IFRS), this announcement does not itself contain sufficient information to comply with IFRS. The financial statements are presented in US dollars which is the functional currency of each of the Company's subsidiary undertakings.

2. Significant accounting policies

(a) Changes in accounting policy
In 2017, the Group has voluntarily changed its accounting policy for intangible exploration and evaluation assets and has adopted the successful efforts method to align with the more prevalent method of accounting for oil and gas assets within its peer group. This has resulted in the Group changing the unit of account used for assessing intangible exploration and evaluation assets for impairment from a licence by licence basis to a well by well basis.

The change in accounting policy has been applied retrospectively and the comparative information has been restated where needed. The table below shows the effect of this change in accounting policy on consolidated income statement, consolidated balance sheet, reported loss for the year, equity, basic and diluted loss per share. There was no impact on the consolidated cash flow statement.

Impact on Consolidated Income	2016 $ million
Decrease in Costs of Sales (depreciation)	15.1
Decrease in Exploration expense	1.1
Increase in Tax	(2.1)
Net reduction in loss for the year	14.1
Impact on loss per share (cents)	
Decrease in basic	4.3
Decrease in diluted	4.3

Impact on Consolidated Balance Sheet	31.12.2016 $ million	01.01.2016 $ million
Decrease in Intangibles assets	(67.6)	(68.7)
Decrease in Property, plant and equipment	(136.4)	(151.5)
Net decrease in assets	**(204.0)**	**(220.2)**
Decrease in Deferred tax liabilities	18.7	20.8
Net decrease in liabilities	**18.7**	**20.8**
Net decrease in net assets	**(185.3)**	**(199.4)**

(b) Basis of preparation

The financial information has been prepared in accordance with the recognition and measurement criteria of IFRS and with IFRSs adopted for use in the European Union. The financial statements have been prepared under the historical cost basis, except for the valuation of hydrocarbon inventory and the revaluation of certain financial instruments.

The Group has a strong financial position and based on future cash flow projections should comfortably be able to continue in operational existence for the foreseeable future. Consequently, the Directors believe that the Group is well placed to manage its financial and operating risks successfully and have prepared the financial information on a going concern basis.

3. Segment information

The Group has one principal business activity being oil and gas exploration and production. The Group's operations are located in South East Asia and Africa (the Group's operating segments) and form the basis on which the Group reports its segment information. There are no inter-segment sales.

				2017
	SE Asia	**Africa [2]**	**Unallocated**	**Group**
	$ million	**$ million**	**$ million**	**$ million**
Oil and gas sales	**156.2**	**-**	**-**	**156.2**
Depreciation, depletion and amortisation	**56.5**	**-**	**0.3**	**56.8**
Exploration expense (see note 6)	**-**	**152.3**	**-**	**152.3**
Profit (loss) before tax [1]	**39.9**	**(152.3)**	**(17.2)**	**(129.6)**
Tax charge (see Note 4)	**27.7**	**-**	**-**	**27.7**

				(Restated) 2016
	SE Asia	Africa [2]	Unallocated	Group
	$ million	$ million	$ million	$ million
Oil and gas sales	154.6	-	-	154.6
Depreciation, depletion and amortisation	64.7	-	0.2	64.9
Exploration write back	-	(2.2)	-	(2.2)
Profit (loss) before tax [1]	32.9	1.7	(12.7)	21.9
Tax charge	25.9	-	0.2	26.1

[1] Unallocated amounts included in profit before tax comprise corporate costs not attributable to an operating segment, investment revenue, other gains and losses and finance costs.

[2] In December 2017, an impairment indicator of IFRS 6 was triggered following the Group's announcement that no substantive expenditure for the Africa assets is either budgeted or planned in the near future. The remaining costs capitalised associated with exploration areas in Africa of $152.3m was fully impaired in the income statement (see Note 6).

Included in revenues arising from South East Asia are revenues of $102.9m and $21.1m which arose from the Group's two largest customers who contributed more than 10% to the Group's oil and gas revenue (2016: $115.1m and $34.1m from the Group's two largest customers).

Geographical information

The Group's oil and gas revenue and non-current assets (excluding other receivables) by geographical location are separately detailed below where they exceed 10% of total revenue or non-current assets, respectively:

Revenue

All of the Group's oil and gas revenue is derived from foreign countries. The Group's oil and gas revenue by geographical location is determined by reference to the final destination of oil or gas sold.

	2017	2016
	$ million	$ million
Vietnam	**105.7**	117.2
Thailand	**36.3**	-
China	**3.3**	33.4
Other	**10.9**	4.0
	156.2	154.6

Non-current assets		(Restated)
	2017	2016
	$ million	$ million
United Kingdom	**0.4**	0.6
Vietnam	**509.3**	555.9
Congo	**-**	100.3
Other - Africa	**-**	48.0
	509.7	704.8

Excludes other receivables.

4. Tax

	2017	(Restated) 2016
	$ million	$ million
Current tax	**42.1**	42.0
Deferred tax	**(14.4)**	(15.9)
	27.7	26.1

The Group's corporation tax is calculated at 50% (2016: 50%) of the estimated assessable profit for the year in Vietnam. During 2017 and 2016 both current and deferred taxation have arisen in overseas jurisdictions only.

The charge for the year can be reconciled to the (loss)/profit per the income statement as follows:

	2017	(Restated) 2016
	$ million	$ million
(Loss)/profit before tax	**(129.6)**	21.9
(Loss)/profit before tax at 50% (2016: 50%)	**(64.8)**	11.0
Effects of:		
Non-deductible expenses	**10.1**	10.9
Tax losses not recognised	**6.2**	5.1
Non-deductible exploration costs written off/(back)	**76.2**	(1.1)
Adjustments to tax charge in respect of previous years	**-**	0.2
Tax charge for the year	**27.7**	26.1

The prevailing tax rate in the jurisdictions in which the Group produces oil and gas is 50%. The tax charge in future periods may also be affected by the factors in the reconciliation above.

The effect of non-deductible exploration costs written off of $76.2m relates to the impairment of exploration assets in Africa (2016 restated: ($1.1m).

Non-deductible expenses primarily relate to Vietnam DD&A charges for costs previously capitalised, which are non-deductible for Vietnamese tax purposes, contributing $6.9m (2016 restated: $8.1m) to the effect of non-deductible expenses. A further $3.2m (2016: $2.8m) relates to non-deductible corporate costs including share scheme incentives.

The effect from tax losses not recognised relates to costs, primarily of the Company, deductible for tax in the UK but not expected to be utilised in the foreseeable future.

5. Loss per share

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

	2017 $ million	(Restated) 2016 $ million
Loss for the purposes of basic loss per share	**(157.3)**	(4.2)
Effect of dilutive potential ordinary shares – Cash settled awards and options	**(0.7)**	(0.5)
Loss for the purposes of diluted loss per share	**(158.0)**	(4.7)

	Number of shares (million)	
	2017	2016
Weighted average number of ordinary shares for the purpose of basic loss per share	**329.8**	329.4
Effect of dilutive potential ordinary shares – Share awards and options	**3.6**	2.8
Weighted average number of ordinary shares for the purpose of diluted loss per share	**333.4**	332.2

In accordance with IAS 33 "Earnings per Share", the effects of antidilutive potential shares have not been included when calculating dilutive loss per share for the year ended 31 December 2017 and prior year.

6. Exploration expense/(write back)

	2017 $ million	(Restated) 2016 $ million
Exploration expense (write back)	**152.3**	(1.1)
Licence commitments (write back)	**-**	(1.1)
	152.3	(2.2)

In December 2017, an impairment indicator of IFRS 6 was triggered following the Group's announcement that no substantive expenditure for those exploration areas in Africa was neither budgeted or planned in the near future. The remaining costs capitalised of $152.3m, after taking into consideration $67.6m which was separately impaired through the restatement of prior year balances due to the change in accounting policy, was fully impaired in the income statement.

7. Property, plant and equipment

As discussed in the Review of Operations, proved and probable oil and gas reserves, audited by Senergy International Sdn Bhd as part of Lloyds Register Group Limited dated 1 October 2017, show a slight decrease to 2P reserves numbers for TGT and a more significant decrease for CNV. This downward revision triggered an impairment test on the Group's CNV asset in Vietnam. No impairment trigger was identified for TGT. The recoverable amount of the CNV producing asset has been determined using the fair value less costs of disposal method which constitutes a level 3 valuation within the fair value hierarchy. The majority of net book value is supported by the fair value derived from a discounted cash flow valuation of the 2P production profile, but with a further portion supported by the risk adjusted incremental value of 2C contingent resources. The key assumptions to which the fair value measurement is most sensitive are oil price, discount rate and 2P reserves. In 2017, the post tax nominal discount rate was lowered from 12.5% to 10% following a change in management of the reservoir and proven reservoir performance which has led to improved technical confidence and therefore a reduced risk profile. As at 31 December 2017, the fair value of the asset is estimated based on a post tax nominal discount rate of 10.0% (2016: 12.5%) and an oil price reflecting a gradual increase over five years from $61/bbl in 2018 (2016: $57/bbl for 2017), to $71/bbl in 2022 (2016: $69/bbl for 2020) plus inflation of 2% (2016: 2%) thereafter.

Testing of sensitivity cases indicated that neither a $5/bbl reduction in the long term oil price nor a 1% increase in discount rates, used when determining fair value less costs of disposal method, would result in an impairment of our CNV oil and gas assets.
Other fixed assets comprise office fixtures and fittings and computer equipment.

8. Financial asset

In 2005, the Group disposed of its Mongolia interest to Daqing Oilfield Limited Company. Under the terms of the transaction the Group was entitled to receive a subsequent payment amount of up to $52.7m, once cumulative production reached 27.8 million barrels of oil, at the rate of 20% of the average monthly marker price for Daqing crude multiplied by the aggregate production for that month. Daqing notified SOCO that the production threshold of crude oil in excess of 27.8 million barrels was achieved in December 2015. The fair value of the subsequent payment amount was determined using a valuation technique as there was no active market against which direct comparisons can be made (Level 3 as defined in IFRS 13). The Directors expected the full subsequent payment amount to be settled by the end of 2016. On 19 December 2016, the Group received the first payment of $10.0m from Daqing Oilfield Limited Company as partial payment for the subsequent payment amount of $52.7m. The full remainder of $42.7m was received in March 2017.

9. Distribution to Shareholders

In June 2017, the Company paid dividends to shareholders of $21.0m (2016: $17.5m) or 5 pence per Ordinary Share (2016: 4 pence per Ordinary Share in two equal payments of 2 pence per share).

The SOCO EBT which is consolidated within the Group, waived its rights to receive a dividend in 2017 and 2016.

The Board is recommending a final dividend for 2017 of 5.25 pence per share, which amounts to approximately $24.3m, assuming that the SOCO EBT waives its entitlement to dividends in respect of its holding of Ordinary Shares. The proposed final dividend is subject to approval by shareholders at the AGM and has not been included as a liability in these Financial Statements. The proposed dividend will be paid on 15 June 2018 to shareholders on the Register of Members at the close of business on 25 May 2018.

10. Reconciliation of operating profit to operating cash flows

	Group		Company	
		(Restated)		
	2017	2016	**2017**	2016
	$ million	$ million	**$ million**	$ million
Operating (loss) profit	**(129.4)**	23.4	**(18.0)**	(12.5)
Share-based payments	**2.0**	1.1	**2.0**	1.1
Depletion and depreciation	**56.8**	64.9	**0.3**	0.2
Exploration expense (write back) (see Note 6)	**152.3**	(2.2)	**-**	-
Operating cash flows before movements in working capital	**81.7**	87.2	**(15.7)**	(11.2)
Decrease (increase) in inventories	**1.5**	(2.6)	**-**	-
Decrease (increase) in receivables	**4.4**	(6.8)	**0.4**	(0.2)
Increase in payables	**0.2**	7.8	**2.4**	3.6
Cash generated by (used in) operations	**87.8**	85.6	**(12.9)**	(7.8)
Interest received	**1.4**	0.4	**-**	-
Interest paid	**-**	(0.1)	**-**	(0.1)
Income taxes paid	**(44.2)**	(39.9)	**-**	-
Net cash from (used in) operating activities	**45.0**	46.0	**(12.9)**	(7.9)

Cash is generated from continuing operating activities only.

11. Preliminary results announced

Copies of the announcement will be available from the Company's head office, situated at 48 Dover Street, London, W1S 4FF and is also available to download from www.socointernational.com. The Annual Report and Accounts, together with notice of the 2018 AGM, will be posted to shareholders in due course.

12. Non-IFRS measures

The Group uses certain measures of performance that are not specifically defined under IFRS or other generally accepted accounting principles. These non-IFRS measures are cash operating cost per barrel, depreciation, depletion and amortisation costs per barrel; and breakeven price per barrel, which are defined below:

Cash operating costs per barrel

Cash operating costs are defined as cost of sales less depreciation, depletion and amortisation, production based taxes, movement in inventories and certain other immaterial cost of sales.

Cash operating costs for the period is then divided by barrels of oil equivalent produced. This is a useful indicator of cash operating costs incurred to produce oil and gas from the Group's producing assets.

Refer to the Financial Review for the calculation.

Depreciation, depletion and amortisation costs per barrel

DD&A per barrel is calculated as Net book value of oil and gas assets in production, together with estimated future development costs over the remaining 2P reserves. This is a useful indicator of ongoing rates of depreciation and amortisation of the Group's producing assets.

Refer to the Financial Review for the calculation.

Breakeven price per barrel

The Group believes this non-IFRS measurement is useful to investors as it provides a guide price at which the Group covers the costs of operations. It is calculated as the sales price (in $/bbl) which is equal to the sum of the Group's 2017 cash operating costs and production based taxes per barrel and the Group's 2017 corporation tax charge per barrel.

Glossary of Terms

$
United States Dollar

£
UK Pound Sterling

1C
Low estimate scenario of Contingent Resources

1P
Equivalent to Prove Reserves; denotes low estimate scenario of Reserves

2C
Best estimate scenario of Contingent Resources

2P
Equivalent to the sum of Proved plus Probable Reserves; denotes best estimate scenario of Reserves. Also referred to as 2P Commercial Reserves

3C
High estimate scenario of Contingent Resources

3P
Equivalent to the sum of Proved plus Probable plus Possible Reserves; denotes high estimate scenario of Reserves

AGM
Annual general meeting

BBL or bbl
Barrel

BHCPP
Bach Ho Central Processing Platform

BLPD or blpd
Barrels of liquids per day

BOE or boe
Barrels of oil equivalent

BOEPD or boepd
Barrels of oil equivalent per day

BWPD or bwpd
Barrels of water per day

CASH or cash
Cash, cash equivalent and liquid investments

CNV
Ca Ngu Vang

CAPEX or capex
Capital Expenditure

Congo (Brazzaville)
The Republic of the Congo

Contingent Resources
Those quantities of petroleum to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies

DD&A
Depreciation, depletion and amortisation

EBT
Employee benefit trust

E&E
Exploration and Evaluation

ERCE
ERC Equipoise

FFDP
Full Field Development Plan

FPSO
Floating, Production, Storage and Offloading Vessel

FY
Full year

G&A
General and administration

HLHVJOC
Hoang Long and Hoan Vu Joint Operating Companies

HLJOC
Hoang Long Joint Operating Company

HVJOC
Hoan Vu Joint Operating Company

IAS
International Accounting Standards

IFRS
International Financial Reporting Standards

JOC
Joint Operating Company

LTI
Lost Time Injury

LTIP
Long Term Incentive Plan

MPS
Mer Profonde Sud

M&A
Mergers and Acquisitions

MMBBL
Million barrels

MMBOE
Million barrels of oil equivalent

OPECO Vietnam
OPECO Vietnam Limited

PEX
Petroleum Exploitation Permit

Petrovietnam
Vietnam Oil and Gas Group

PSC
Production sharing contract or production sharing agreement.

PTTEP
PTT Exploration and Production Public Company Limited

Reserves
Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial and remaining based on the development projects applied

Shares
Ordinary Shares

SOCO Cabinda
SOCO Cabinda Limited

SOCO Congo
SOCO Congo Limited

SOCO EPC
SOCO Exploration & Production Congo SA

SOCO Vietnam
SOCO Vietnam Ltd

STOIIP
Stock Tank Oil Initially In Place

TGT
Te Giac Trang

UK
United Kingdom

US
United States of America

WHP
Wellhead Platform