**SOCO International plc**
("SOCO" or the "Company")

# PRELIMINARY RESULTS

SOCO, an international oil and gas exploration and production company, today announces its preliminary results for the year ended 31 December 2015.

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

"Although no one in this industry is immune to the pricing storms that surround us, because of our business model and strong balance sheet, we are in a good position to take advantage of the opportunities available to build for the future. We are focusing on synergistic acquisition situations offering complementary cash generative strength as well as exploration opportunities providing future drilling optionality. Above all, we intend to manage this approach with the overall objective of targeting sustainable cash returns to shareholders."

## OPERATIONAL HIGHLIGHTS

### Vietnam

- Annual production net to the Group's working interest averaged 11,976 barrels of oil equivalent per day ("BOEPD") (2014: 13,605 BOEPD); at the top end of our guidance range
  - Te Giac Trang ("TGT") Field production averaged 34,032 BOEPD gross and 10,227 BOEPD net
  - Ca Ngu Vang ("CNV") Field production averaged 6,997 BOEPD gross and 1,749 BOEPD net
- First oil from TGT H5 development achieved on 10 August 2015
  - Delivered under budget and more than one month ahead of schedule
  - Exemplary health and safety record of 2.4 million man hours without a lost time incident
- Updated Reserve Assessment Report completed by Hoang Long JOC
  - Approved by PetroVietnam; final approval from Vietnamese Government expected Q2 2016
- Group year-end 2015 commercial reserves 37.3 MMboe (2014: 40.8 MMboe) following production and modest upward revision
- Memorandum of Understanding signed for Blocks 125/126, offshore central Vietnam; work is ongoing towards formalisation of a Production Sharing Agreement

### Africa

- 12 month extension granted on the Marine XI licence
- All commitments under Mer Profonde Sud ("MPS") licence have been completed

## FINANCIAL HIGHLIGHTS

- Ongoing balance sheet strength; year-end cash balance of $103.6m and no debt
- Capital expenditure of $87.5m (2014: $162.5m)
- Cash operating costs were approx. $10 per barrel
- Revenue $214.8m (2014: $448.2m)
  - Average realised crude oil price approx. $54 per barrel; $2 per barrel premium to Brent
  - Net cash generated from operations $80.3m (2014: $251.2m)

- After tax loss $33.8m (2014: $14.0m profit) after exploration expenses, including Baobab Marine-1 well on MPS
- No impairment of our producing assets in the period (2014: $60.5m)
- Recommended dividend of 2 pence per share (approx. $9.5m) to be approved at the AGM
  - Distribution made to shareholders during 2015 of $51.1m (2014: $119.2m)
  - $383.6m returned to shareholders over the past three years

## OUTLOOK FOR 2016

- 2016 exploration and development programme is fully funded from existing cash resources
- 2016 financial and operating metrics
  - 2016 production guidance 10-11,500 BOEPD
  - Operating expenditure expected to remain at approx. $10 per barrel
  - 2016 firm capex budget of $54m including MPS well costs provided for in 2015; Vietnam $18m
- A Full Field Development Plan for TGT has been updated during the year. Expected submission by to the relevant Vietnamese authorities Q2 2016
- Deferred payment of $52.7m associated with 2005 sale of Mongolia interests expected to be fully received in next 12 months
- Additional distribution to shareholders to be considered in H2 2016
- Ongoing focus on sustainable cash flow generation and commitment to strategy of cash returns

## ENQUIRIES:

**SOCO International plc**
Roger Cagle, Deputy Chief Executive and Chief Financial Officer
Antony Maris, Chief Operating Officer
Tel: 020 7747 2000

**Bell Pottinger**
Nick Lambert
Elizabeth Snow
Tel: 020 3772 2500

## NOTES TO EDITORS

SOCO is an international oil and gas exploration and production company, headquartered in London and traded on the London Stock Exchange. The Company has field development and production interests in Vietnam and exploration and appraisal interests in the Republic of Congo (Brazzaville) and Angola.

In accordance with DTR 6.4, SOCO has notified the FCA that its home member state is the United Kingdom. SOCO is registered in England and Wales; company registration number 03300821.

# CHAIRMAN AND CHIEF EXECUTIVE'S STATEMENT

Although 2015 was a continuation of the tough industry environment which began the previous year, when assessed on the basis of those things over which the Company could exercise some element of control, SOCO performed well and emerged in excellent shape.

We allocated capital to those projects that positively impacted the bottom line. We cut costs by renegotiating reductions in vendor contracts and services. We closed offices and deferred any cash bonuses to executives. We deferred projects to take advantage of an improving cost environment. All this and we still returned $51.1m to shareholders whilst maintaining a strong balance sheet with a year-end cash balance of $103.6m and no debt.

The Company is staffed and managed by people who have extensive experience in this industry and we are accustomed to having to deal with its cyclical nature. Thus, whilst we are impacted by the downturn and it affects our decision making, the business remains resilient, well positioned and robust, with a strong balance sheet and a cash break even oil price in the low $20 per barrel range.

With our significant financial flexibility, fully funded capital programme and strict cost discipline, we can continue our strategy of focusing on delivering to shareholders both value – through cash returns – and growth, be it organic or inorganic. The short term priority is to shape the business, which is already resilient in a downside scenario of persistent low oil prices, and to ensure that we are positioned for delivering sustainable growth as the oil price recovers.

## 2015 PERFORMANCE

Against the poor industry back drop, 2015 was another solid year for SOCO. We sustained our policy of returning cash to shareholders by declaring a final dividend for 2014 and paying out $51.1m to shareholders. We brought the H5 development into production ahead of schedule and below budget, and maintained our exemplary health and safety record.

Group production of 11,976 barrels of oil equivalent per day ("BOEPD") was at the top end of our guidance range, down from 13,605 BOEPD in 2014. The year-on-year drop was mainly attributable to a slowing of investment on the TGT Field thus allowing the higher water cut producing wells to force us into capacity limits on the shared FPSO.

Directly correlating with the approximately 50% decline in oil prices (from $103 per barrel in 2014 to $54 per barrel) and lower production, revenue dropped from $448.2m in 2014 to $214.8m. The Group posted a loss of $33.8m (2014: $14.0m profit) in the period after taking account of exploration expenses. The 2015 exploration expenses were primarily associated with the costs to complete the Mer Profonde Sud licence commitments of $36.4m (2014: $79.5m). There has been no impairment of our producing assets in the period (2014: $60.5m).

Net cash generated from operations, again reflecting lower sales and declining oil prices, fell to $80.3m in 2015, down from $251.2m in 2014. Capital expenditure essentially halved, dropping from $162.5m in 2014 to $87.5m as we slowed spending not directly tied to adding value to the bottom line and postponed non-essential spending.

SOCO made its first dividend distribution in 2015 of $51.1m shelving returns via B/C share schemes which are no longer available, which paid out $119.2m to shareholders in 2014. SOCO has returned $383.6m to shareholders over the past three years putting it into a class of its own amongst our peer independent E&P companies.

## Vietnam

**Te Giac Trang ("TGT") Field**

*(30.5% working interest; operated by Hoang Long Joint Operating Company ("HLJOC"))*

TGT Field production for 2015 averaged 34,032 BOEPD gross and 10,227 BOEPD net to SOCO's working interest.

The H5 development was successfully brought on stream on 10 August 2015, more than one month ahead of schedule, under budget and with a total of 2.4 million man hours without a lost time incident.

The updated Reserve Assessment Report has been completed by HLJOC and approved by PetroVietnam. The formal presentation to the relevant Vietnamese authorities has been made and final approval is expected in Q2 2016. Following receipt of the approval, the revised Full Field Development Plan ("FFDP") is expected to be submitted for approval in Q2 2016. The scope of the development programme in the FFDP is expected to include additional wells and facilities options to increase water handling capacity.

The capital expenditure budget for Vietnam is approx. $18m, which includes long lead items for four wells for the ongoing TGT Field development, the cost attributed to completing drilling activities on TGT-14X appraisal well and new venture costs associated with Blocks 125/126. For 2016, no firm production target has been agreed between the HLJOC partners pending agreement on the scope of the FFDP, as well as receipt of optimised 2016 production scenarios from the HLJOC utilising full reservoir potential from existing wells. The 2016 contingent capital budget covers the drilling costs for the wells, as well as costs associated with water handling facilities upgrade following FFDP approval.

The TGT Field has attractive economics and cost recovery terms, low operating costs and a benign operating and geopolitical backdrop. Moreover, the field economics also mean that the cash flow profile and returns are significantly geared to the oil price.

Proven and probable reserves for the TGT Field were broadly flat year-on-year reflecting the lack of further investment in the field, whilst the new H5 production partially offset the higher water cut coming from the older producing platforms. After adjustments for production during the year (3.7MMboe) and a modest downward revision (2.2MMboe), 2P commercial reserves for the TGT Field were 30.6MMboe as at 31 December 2015.

**Ca Ngu Vang ("CNV") Field**

*(25% working interest; operated by Hoan Vu Joint Operating Company ("HVJOC"))*

CNV Field production for 2015 averaged 6,997 BOEPD gross and 1,749 BOEPD net to the Company's working interest.

The HVJOC is evaluating the impact of the reservoir pressure drop from reduced water injection on the long-term performance and recovery of the field, as well as looking into potential ways of maintaining production performance and improving recovery from the field. The initiatives for the latter include conversion of the CNV-6P-ST1 injection well to a producer and modification of processing facilities on the Bach Ho platform to lower minimum tubing head pressure. Discussions with the owner of the Bach Ho processing facilities are under way.

Year-end proven and probable reserves for the CNV Field were increased after an over 80% upward revision (3.0MMboe) and production of 0.6MMboe, ending the year at 6.7MMboe.

**Vietnam New Ventures**

On 29 July 2015, SOCO signed a Memorandum of Understanding with PetroVietnam and SOVICO Holdings regarding obtaining petroleum contracts on Blocks 125/126, offshore central Vietnam. Work is ongoing towards formalisation of a Production Sharing Agreement.

## Africa Exploration

**Marine XI**

*(Operated, 40.39% working interest)*

Following the successful Lidongo X Marine 101 exploration well drilled in 2014 on the Marine XI Block offshore Congo (Brazzaville), the focus turned to two things; discussion with authorities regarding commercialisation options for the Lidongo discovery area, along with potentially other prior discoveries on the Block, and reprocessing of our 3D seismic previously acquired over Marine XI. Options for commercialisation alternatives were limited as block expiry was scheduled for March 2016; however, the Congolese authorities agreed in early 2016 to a 12 month licence extension.

With the Lidongo well suggesting a possible extension into our Block of the Litchendjili Field on the Marine XII Block, which began production in 2015, we entered into an agreement with the interest holders of Block XII to explore options for a potential joint development or unitisation. Although a data exchange has taken place, substantive discussions have not yet begun.

The Marine XI partners have prepared a Production Licence Application, which has been submitted to the Congolese authorities. Meanwhile interpretation of the reprocessed seismic is ongoing.

**Mer Profonde Sud**

*(Operated, 60% working interest)*

The Mer Profonde Sud Block is located in the Lower Congo Basin, offshore Congo (Brazzaville). SOCO farmed into the Block in November 2013 with a 60% working interest (100% carried interest for one well) and assumed operatorship. Regulatory approval was granted in the first quarter of 2014.

The Block was in its third and final period of the exploration licence with a mid-2016 expiry. The licence carried an obligation to drill an exploration well.

In February 2016, the well was drilled on the RR Prospect to a measured depth of 3,275 metres and intersected the stacked early Miocene channel complexes that were targeted. Although good quality sands were present, no hydrocarbons were encountered, suggesting lack of communication with the known oil source. The well was plugged and abandoned and the drilling programme was executed under budget.

**Cabinda North**

*(Non-operated, 17% working interest)*

Discussions are ongoing among the partners and with the authorities to agree the new partnership, operator and activities during the licence extension period to April 2018.

## CORPORATE

### Non-Executive Directors

Corporate governance remains a priority and the Company has initiated a further programme of Board refreshment with two long serving Non-Executive Directors, John Norton and Robert Cathery, not seeking reappointment at the upcoming AGM. We thank both for their many years of excellent service to the Company, throughout which they continued to discharge their duties with the rigour and objectivity expected of fully independent Non-Executive Directors.

We appreciate their valuable contribution during the induction and assimilation of our most recent appointments. Accordingly, we believe that the continuing Directors will comprise an appropriately balanced Board with the experience and attributes critical to the success of the Company.

We will continue to review the balance and effectiveness of the Board with a view to adding independent non-executives commensurate with our size and need.

## Dividend

The Company has a strong track record of managing its asset and capital base effectively which has enabled it to return approximately $438m to shareholders over the last seven years via dividends, capital returns and share buybacks. This prudent and rigorous approach to capital has served the Company well even in the face of the recent, very significant decline in the oil price. Indeed, even at current oil prices, SOCO continues to generate solid cash flow, has a strong balance sheet with over $100m of cash and no debt.

The Board of SOCO has a very clearly defined approach to capital which is to:

- Retain a strong balance sheet under all oil price scenarios;
- Pay a sustainable dividend to shareholders;
- Invest organically and inorganically in attractive risk / return profile projects; and
- Periodically assess, in light of the prevailing environment, uses for excess capital and consider additional capital returns

In light of this capital allocation philosophy and to emphasise our intent for the sustainability of creating value for our shareholders, the Board has proposed a final dividend for the year ended 31 December 2015 of 2 pence per share which will be recommended for shareholder approval at the Annual General Meeting to be held in June of this year. Further, given an oil price at or above current levels and no major adverse surprises in our budget for the year, we anticipate that the Board will at mid-year results propose a special payout to be distributed in the second half of the year.

## OUTLOOK

We remain committed to evaluating alternatives to optimise our exposure to upside without jeopardising our focus on sustainable cash flow generation. We expect to secure synergistic, longer term opportunities that offer exploration drilling optionality in a more robust environment without putting our dividend policy in jeopardy. We are refocusing our business in South East Asia as past merger and acquisition activity has substantially reduced the number of competitors in the region. We understand the region, particularly Vietnam, and have had considerable success there in the past, which we aim to repeat in the future.

In January 2016 and prior to firm agreement on the TGT FFDP, we set our production guidance range for 2016 to 10-11,500 BOEPD. The lower end reflects limited reservoir management and natural field decline. The upper end reflects the additional optimised reservoir management with production from potential newly drilled wells. However, if non-essential capital outlay does not contribute directly to the bottom line, we do not expect to go forward with the expenditure at this time.

Thus continuing from last year, our operational focus for 2016 will be on working with the TGT partners to submit the updated TGT FFDP in Q2 2016. Otherwise, it will be a year of prudent cost management whilst taking proactive measures to ramp the TGT development programme back up when conditions are more conducive and positioning ourselves for future growth.

At budgeted oil prices for 2016 and based on ongoing correspondence with the counter party, we project that the deferred payment of $52.7m associated with the 2005 sale of our Mongolian interests to be fully received in the next 12 months.

Current market conditions notwithstanding, our strategy of targeting sustainable cash returns to shareholders remains.

With our consistent long term approach to appropriate resourcing and diligent spending, we believe that we are well placed to take advantage in this difficult and sustained economic climate, unlike many of our peers who are focusing on survival or care and maintenance. We hope to seize real opportunities as they arise and continue our focus on creating value for our shareholders.

**Rui de Sousa**
Chairman

**Ed Story**
President and Chief Executive Officer

# REVIEW OF OPERATIONS

Operations during 2015 focussed on the Te Giac Trang ("TGT") Field development programme, offshore Vietnam. Development drilling on the H5 Fault Block of TGT, following a discovery well in 2014, was successfully completed leading to first oil from H5 in August 2015, ahead of schedule and below budget. On the H4 Fault Block, field development progressed with the addition of three producing wells. The TGT Field, which was discovered in 2005 and achieved first oil in 2011, is now producing from three platforms with 26 producing wells and one injector well.

In Africa, operations were focused on completing the analysis of data from the successful exploration well drilled on the Marine XI Block in 2014 and, particularly during the second half of the year, on the preparation for the Company's first operated deep water well on the Mer Profonde Sud Block, both offshore Congo (Brazzaville).

Group production for 2015 averaged 11,976 BOEPD (2014: 13,605 BOEPD) with all production coming from the Company's interests in Vietnam.

## VIETNAM

In Vietnam, SOCO's Block 16-1 and Block 9-2, which comprise the TGT and Ca Ngu Vang ("CNV") Fields, respectively, are located in shallow water in the oil rich Cuu Long Basin, near the Bach Ho Field, the largest field in the region which has produced more than one billion barrels. 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.

SOCO holds a 30.5% working interest in Block 16-1 and a 25% working interest in Block 9-2 through its wholly owned subsidiaries, SOCO Vietnam Ltd and OPECO Vietnam Limited. SOCO's partners in both Blocks are PetroVietnam, the national oil company of Vietnam, and PTTEP, the national oil company of Thailand.

### Production

During 2015, production net to SOCO's working interest was 10,227 BOEPD (2014: 11,538 BOEPD) from TGT and 1,749 BOEPD (2014: 2,067 BOEPD) from CNV. The average realised crude oil price for 2015 was approximately $54 per barrel, a premium of $2 per barrel to Brent.

| Production by field | FY 2015 | FY 2014 |
|---|---:|---:|
| **TGT Production** | **10,227** | **11,538** |
| Oil | 9,397 | 10,464 |
| Gas[1] | 830 | 1,074 |
| **CNV Production** | **1,749** | **2,067** |
| Oil | 1,204 | 1,423 |
| Gas[1] | 545 | 644 |
| **Total Production** | **11,976** | **13,605** |
| Oil | 10,601 | 11,887 |
| Gas[1] | 1,375 | 1,718 |

*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 by Hoang Long Joint Operating Company ("HLJOC"))*

The TGT Field is located in the north eastern part of Block 16-1 offshore Vietnam and is operated by HLJOC. SOCO's interest in the Block was awarded in December 1999 and the first commercial discovery was made in 2005.

TGT is a simple structure, with complex production intervals, extending over 16 km and with hydrocarbons located in at least five major fault blocks. The producing reservoir comprises a complex series of over 50 clastic reservoir intervals of Miocene and Oligocene age. Each reservoir interval requires individual reservoir management to optimise field recovery. The TGT Field has been a rewarding investment for SOCO with its attractive economics and cost recovery terms, along with low operating costs, and a benign operating and geopolitical backdrop.

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 a floating, production, storage and offloading vessel ("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.

**TGT H5 Development**

The third TGT platform, H5-WHP, was successfully brought onstream on 10 August 2015, more than one month ahead of schedule. The project was completed under budget and with a total of 2.4 million man-hours without a lost time incident.

The H5 Field Development Plan, comprising a 6 well drilling programme, had been approved in September 2014, at the same time as the H5-WHP jacket and drilling deck installation, which allowed drilling to commence from mid-September 2014 with the TGT-22P well.

The second and third wells, TGT-23P and TGT-24P, were completed in early January 2015, followed by the TGT-12X well, which appraised the previously undrilled H5N fault block. The fifth development well, TGT-25P, also appraised the deeper Oligocene section. The wells were then all completed and suspended ahead of the final hook up and completion of the development programme. Due to insufficient rig time, the H5S fault block appraisal well, TGT-14X, was deferred into the next drilling campaign.

H5 currently has production from all five wells drilled from the platform, the TGT-22P, TGT-23P, TGT-24P and TGT-25P producers and the TGT-12X-ST1 appraisal well. Two of the producer wells and the TGT-12X-ST1 well have been perforated in the lower Miocene reservoirs, and two in the Oligocene reservoir. Current H5 gross production is approximately 8,000 BOPD, which is lower than the 11-12,000 BOPD originally targeted. The Miocene wells are producing as expected, but the Oligocene wells are underperforming due to lower reservoir permeability than predicted. Work is ongoing to identify actions to optimise H5 performance from existing wells.

Analysis of well drilling results has indicated that the upper part of the Miocene reservoir is oil bearing, rather than gas bearing as originally believed. The H5 wells have not yet been perforated in this interval and there is significant additional H5 production potential in currently unperforated intervals. The scope of additional perforations is expected to be defined in the revised development plan discussed below.

**TGT H4 In-field Development**

In addition to the TGT H5 development wells, three in-field development wells, TGT-20P-ST1, TGT-21P and TGT-26P, were drilled during the year from the H4 platform.

The TGT-20P-ST1 well, an H4 in-fill producer, encountered completion problems in the targeted Oligocene section and was completed in the Miocene section instead. The subsequent TGT-26P well was therefore modified and deepened to encounter the Oligocene and replace the TGT-20P-ST1 as an Oligocene producer. The TGT-21P was drilled as an H3N in-fill producer. These wells have been completed and are producing as expected.

**TGT Performance Evaluation and Prediction**
Following the original building of the Geological Model and the Dynamic Simulation Model in 2014, SOCO retained ERC Equipoise to update both the Geological Model and the Dynamic Simulation Model of the TGT Field with the new wells from 2015 and the additional production history. This work involved a reworking of all the fundamental input geoscience data and encompassed almost a year's work of a multi-disciplinary team. This activity highlights the significant complexity and technical uncertainty of the field. In essence, the reworking added some degree of complexity to the previous model.

The reworked Dynamic Model has been history matched against the field production data to date and then a series of forecasts run to evaluate the ultimate oil volume recoverable given various levels of development drilling and pressure maintenance under various FPSO and alternative liquid handling options.

This work demonstrates a significant range of potential development scenarios depending on the level of development drilling, infrastructure optimisation and upgrade, as well as reservoir performance management to optimise field recovery. The output from the model has been reviewed by the reserve auditor and is being used to focus on the development programme choices required for the revised Full Field Development Plan ("FFDP").

**TGT Reserve Assessment Report ("RAR")**
The updated RAR was completed during the year and was approved by PetroVietnam. Formal presentation to the relevant Vietnamese authorities has been done and final approval from the Vietnamese Government is expected in Q2 2016.

**Forward Plans**
A FFDP for TGT has been updated during the year and is expected to be completed for submission by the HLJOC partners to the relevant Vietnamese authorities in Q2 2016. The updated FFDP will incorporate the development plans for the TGT Field beyond 2016 and is expected to include additional wells and facilities options to increase liquid handling capacity. However, the scope of the development programme in the updated FFDP will largely depend on the oil price outlook at the time and HLJOC partners' alignment on a development path and appetite to commit capital.

Evaluation of all options remains ongoing. This includes evaluating how production from TGT could be increased from the existing well stock by perforating additional horizons, optimising reservoir management by shutting off higher water-cut wells, as well as the consideration of infill well locations. At the same time, evaluation of small investment, late field life acceleration projects are also being considered.

Given the current climate, all the equipment and service contracts are under review to seek reduced operating and capital costs. We have also identified contracts where alternative commercial structures, which may be of benefit to both parties, could be negotiated in order to enhance the value of the Field.

For 2016, no firm production target has been agreed between the HLJOC partners pending agreement on the scope of the FFDP, as well as receipt of optimised 2016 production scenarios from the HLJOC utilising full reservoir potential from existing wells. Pending the FFDP, the HLJOC partners have agreed to purchase the long lead items for four wells plus those attributed to finishing drilling the TGT-14X appraisal well with the 2016 contingent capex budget covering the drilling costs for the wells, as well as the capital associated with a water handling facilities upgrade following FFDP approval.

## Block 9-2 – CNV Field

*(25% working interest; operated by Hoan Vu Joint Operating Company ("HVJOC"))*

The CNV Field is located in the western part of Block 9-2 offshore Vietnam and is operated by the HVJOC. SOCO's working interest production from CNV averaged 1,749 BOEPD in 2015 (2014: 2,067 BOEPD). In contrast to TGT, the CNV Field reservoir is fractured granitic basement which produces highly volatile oil with a high gas to oil ratio and exploitation is dependent on the fracture interconnectivity to deplete the reservoir efficiently. Accordingly, traditional reservoir properties and Stock Tank Oil Initially In Place (“STOIIP”) calculations are not straightforward.

Hydrocarbons produced from CNV are transported via subsea pipeline to the Bach Ho Central Processing Platform (“BHCPP”) where wet gas is separated from oil and transported via pipeline to an offshore gas facility for further distribution. The crude oil is stored on a floating, storage and offloading vessel prior to sale. On the BHCPP, dedicated test separation and metering facilities have been installed.

While the field has been performing steadily, the anticipated indications of injector-producer linkage were identified in the year. Originally, the CNV-7P well was identified as the main option to overcome this. With operational complications preventing the drilling of the CNV-7P well in 2014, the HVJOC has been reviewing alternative options to maintain production performance. With the need to reduce water injection and accept the subsequent reduction in reservoir pressure from lower water pressure maintenance, the HVJOC has reviewed alternatives to maximise the long-term performance and recovery of the field.

The initiatives for the latter include conversion of the CNV-6P-ST1 injection well to a producer and modification of processing facilities on the Bach Ho platform to lower minimum tubing head pressure. The conversion of the former injector well to a producer is to take advantage of the movement from bottom-up “water-based” pressure maintenance to using the liberated gas in the reservoir as the “top-down” reservoir drive mechanism. The liberated gas displaces the oil from the upper parts of the reservoir and acts as a pressure drive from above. The approval to convert the well has been received and activities to do this are ongoing.

Discussions with the owner of the Bach Ho processing facilities are underway regarding the process facility modifications and work on the engineering design requirements has commenced.

Year-end proven and probable reserves for the CNV Field were increased after an over 80% upward revision of 3.0MMboe and after production of 0.6MMboe, ending the year at 6.7MMboe.

### Vietnam New Ventures

On 29 July 2015, SOCO signed a Memorandum of Understanding with PetroVietnam and SOVICO Holdings regarding obtaining petroleum contracts on Blocks 125/126, offshore central Vietnam. Work is ongoing towards formalisation of a Production Sharing Agreement.

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. Interpretation of the available data indicates there is good potential for source, expulsion and migration of oil with numerous reservoir and seal intervals likely.

## REPUBLIC OF CONGO (BRAZZAVILLE)

SOCO holds its interests in the Marine XI Block, located offshore Congo (Brazzaville) in the shallow water Lower Congo Basin, through an 85% owned subsidiary, SOCO EPC. SOCO holds a 60% working interest in the Mer Profonde Sud Block, offshore Congo (Brazzaville) through its wholly owned subsidiary, SOCO Congo BEX Limited.

### Marine XI

*(Operated, 40.39% working interest)*

Results from the successful Lidongo X Marine 101 well, drilled in 2014, were analysed during the year to determine continuity with the nearby discovery on Marine XII. Reprocessing of the full 3D seismic data set over the Block was completed at year end. The seismic volume was much improved by the reprocessing, although mapping at the Djeno and Vandji levels remains challenging. A detailed interpretation and evaluation of the prospect inventory identified in the reprocessed seismic is ongoing.

SOCO continues its discussions with the Congo authorities regarding commercialisation options for the Lidongo discovery area. The Marine XI partners have prepared a Production Licence Application, which is in the process of being evaluated by the relevant authorities, as a first stage in securing the authorisation from the relevant authorities for formal discussions with the Marine XII partners concerning the continuity and extension of the nearby field.

Subject to finalising specific details, the Congolese authorities have agreed to a 12 month extension to the previous March 2016 licence expiry. This allows for completion of the evaluation and interpretation of the 2015 reprocessed seismic data. Once complete this will influence any further activity on Marine XI, outside the area under consideration for unitisation.

### Mer Profonde Sud ("MPS")

*(Operated, 60% working interest)*

Under a 2013 farm-in agreement, SOCO acquired operatorship of the MPS Block and agreed to drill one commitment exploration well in the remaining licence period, which was extended by agreement with the relevant authorities to 31 May 2016.

The Baobab Marine-1 well spudded on the RR Prospect on 5 February 2016. The well reached total measured depth of 3,275 metres on 25 February and intersected the stacked early Miocene channel complexes that were targeted. Although good quality sands were present, no hydrocarbons were encountered, suggesting lack of communication with the known oil source. The well was subsequently plugged and abandoned.

Although the cost of the well was fully carried by SOCO, the current climate for equipment and services allowed the well to be drilled at a significantly reduced cost to original expectations, with the final Authorisation for Expenditure ("AFE") being about one third of the original estimate and approximately 50% of the initial cost estimate. Execution management of the well meant that the overall cost of the well still came in below the final AFE. The well was also drilled with no lost time incidents.

## ANGOLA

### Cabinda North Block

*(Non-operated, 17% working interest)*

SOCO's 85% owned subsidiary, SOCO Cabinda Limited, holds a 17% participation interest in the Production Sharing Agreement for the Cabinda North Block, onshore the Angolan Cabinda enclave.

Whereas the licence was due to expire in 2015, the Angolan authorities issued a decree, gazetted on 21 April 2015, to extend the licence by three years. Discussions are ongoing among the partners and with the authorities to agree the new partnership, operator and activities during the licence extension period to April 2018.

## DEMOCRATIC REPUBLIC OF CONGO (KINSHASA) ("DRC")

Following the end of our contractual obligations to the Government of the DRC, SOCO did not seek to renew the Block V licence. In 2015, SOCO finalised its relinquishment of the licence. This is in accordance with its public commitments made in 2014. The closure of the SOCO office in Kinshasa was completed by the end of the year. SOCO holds no licence interests in the DRC.

## GROUP RESERVES AND CONTINGENT RESOURCES

An independent audit of management estimates of Reserves and Contingent Resources for TGT and CNV, as of 31 December 2015, was completed by Gaffney, Cline and Associates in March 2016.

### TGT Reserves and Contingent Resources

The year-end 2015 TGT estimated reserves are based on the scope of already approved wells, with consideration given to a small number of likely near-term wells, optimal field management and increased liquid handling capacity of the FPSO. A commercial offer is being negotiated with the FPSO owner, which will allow access to additional liquid handling capacity for a small day rate increase. All volumes beyond this scope of approved development activities were classified as contingent.

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, estimated oil in place, reserves and resources based on a limited number of layers with a more simplified "averaging" of reservoir properties and using single oil-water-contacts across contiguous producing intervals. Increased computer processing power coupled with increased production history on a sand-by-sand basis has meant that the revised model now subdivides the original delineated producing intervals. Each subdivided layer has its own allocated reservoir properties and oil-water-contacts. Due to the shallow relief architecture of the reservoir sands this has a greater impact on the mid-case probabilistic STOIIP model and subsequent mid-case reserves and resources.

| TGT Field Oil-In-Place Estimates (MMbbl) | | | |
|---|---|---|---|
| | **P90** | **P50** | **P10** |
| Stock Tank Oil Initially in Place | 376 | 603 | 943 |

| TGT Field Estimated Ultimate Recovery<br>Inception to Year End 2015 | | | |
|---|---|---|---|
| **Reserves + Production** | **1P** | **2P** | **3P** |
| Oil | 110.2 | 155.1 | 190.0 |
| Gas[1] | 8.3 | 11.0 | 14.5 |
| Total | 118.5 | 166.1 | 204.5 |
| **Contingent Resources** | **1C** | **2C** | **3C** |
| Oil | 15.0 | 45.0 | 110.0 |
| Gas[1] | 1.1 | 3.3 | 9.7 |
| Total | 16.1 | 48.3 | 119.7 |
| **Total Ultimate Recovery** | **1P & 1C** | **2P & 2C** | **3P & 3C** |
| Oil | 125.2 | 200.1 | 300.0 |
| Gas[1] | 9.4 | 14.3 | 24.2 |
| Total | 134.6 | 214.4 | 324.2 |

*Figures in MMboe*

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

*[2] This table has been derived by SOCO from the audited figures.*

| **SOCO Working Interest Reserves and Resources<br>TGT Field at 31 December 2015** | | | |
|---|---|---|---|
| **Reserves** | **1P** | **2P** | **3P** |
| Oil | 15.5 | 29.0 | 39.5 |
| Gas[1] | 0.8 | 1.6 | 2.7 |
| Total | 16.3 | 30.6 | 42.2 |
| **Contingent Resources** | **1C** | **2C** | **3C** |
| Oil | 4.5 | 13.0 | 31.8 |
| Gas[1] | 0.3 | 1.0 | 2.9 |
| Total | 4.8 | 14.0 | 34.7 |
| **Sum of Reserves and Contingent Resources** | **1P & 1C** | **2P & 2C** | **3P & 3C** |
| Oil | 20.0 | 42.0 | 71.3 |
| Gas[1] | 1.2 | 2.6 | 5.6 |
| Total | 21.2 | 44.6 | 76.9 |

*Figures in MMboe*

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

[2] *The summation of reserves and Contingent Resources has been prepared by the Company.*

## 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 will change the drive mechanism from "bottom-up" water drive to "top-down" gas drive, as due to the volatile nature of the oil, gas will be liberated 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. Volumes associated with the CNV-7P and future wells are included in Contingent Resources. The revised ERCE model yields an increase in both reserves and resources over 2014.

| **SOCO Working Interest Reserves and Contingent Resources<br>CNV Field at 31 December 2015** | | | |
|---|---|---|---|
| **Reserves** | **1P** | **2P** | **3P** |
| Oil | 4.0 | 4.9 | 5.6 |
| Gas[1] | 1.5 | 1.8 | 2.2 |
| Total | 5.5 | 6.7 | 7.8 |
| **Contingent Resources[2]** | **1C** | **2C** | **3C** |
| Oil | - | 6.1 | 6.6 |
| Gas[1] | - | 2.9 | 3.0 |
| Total | - | 9.0 | 9.6 |
| **Sum of Reserves and Contingent Resources[2]** | **1P & 1C** | **2P & 2C** | **3P & 3C** |
| Oil | 4.0 | 11.0 | 12.2 |
| Gas[1] | 1.5 | 4.7 | 5.2 |
| Total | 5.5 | 15.7 | 17.4 |

*Figures in MMboe*

[1] *Assumes oil equivalent conversion factor of 6,000 standard cubic feet per barrel of oil equivalent.*
[2] *3C Contingent Resources are unaudited and reflect Management's estimates.*
[3] *The summation of reserves and Contingent Resources has been prepared by the Company.*

## Viodo Reserves and Contingent Resources

There are no plans for commercial standalone development of the Viodo Field in the Marine XI Block at this time. However, there remains potential to recognise additional Contingent Resources on the Marine XI Block from Lideka East, and from the Lidongo Discovery as it is progressed towards unitisation with the nearby Litchendjili Field which has commenced production.

| SOCO Working Interest Contingent Resources<br>Viodo Field at 31 December 2015 | |
|---|---|
| **Contingent Resources** | **2C** |
| Oil | 8.1 |
| Gas | - |
| Total | 8.1 |

*Figures in MMbbl*

## Consolidated Income Statement

for the year to 31 December 2015

| | Notes | 2015 $ million | 2014 $ million |
|---|---|---|---|
| Revenue | 4 | **214.8** | 448.2 |
| Cost of sales | | **(166.4)** | (143.8) |
| **Gross profit** | | **48.4** | 304.4 |
| Administrative expenses | | **(10.0)** | (11.8) |
| Pre-licence exploration costs | | **(0.8)** | - |
| Exploration expense | 7 | **(35.6)** | (79.5) |
| Impairment of property, plant and equipment | 8 | **-** | (60.5) |
| **Operating profit** | | **2.0** | 152.6 |
| Investment revenue | | **0.4** | 0.7 |
| Other gains and losses | | **7.4** | 1.6 |
| Finance costs | | **(1.6)** | (2.2) |
| **Profit before tax** | 4 | **8.2** | 152.7 |
| Tax | 4, 5 | **(42.0)** | (138.7) |
| **(Loss) profit for the year** | | **(33.8)** | 14.0 |
| **(Loss) earnings per share (cents)** | 6 | | |
| **Basic** | | **(10.3)** | 4.3 |
| **Diluted** | | **(10.3)** | 4.2 |

## Consolidated Statement of Comprehensive Income

for the year to 31 December 2015

| | 2015 $ million | 2014 $ million |
|---|---|---|
| (Loss) profit for the year | **(33.8)** | 14.0 |
| Items that may be subsequently reclassified to profit or loss: | | |
| Unrealised currency translation differences | **1.8** | (1.8) |
| **Total comprehensive (loss) income for the year** | **(32.0)** | 12.2 |

# Balance Sheets

as at 31 December 2015

| | | Group | | Company | |
|---|---|---|---|---|---|
| | | **2015** | 2014 | **2015** | 2014 |
| | Notes | **$ million** | $ million | **$ million** | $ million |
| **Non-current assets** | | | | | |
| Intangible assets | 7 | **211.5** | 209.1 | **-** | - |
| Property, plant and equipment | 8 | **760.5** | 790.0 | **0.8** | 1.0 |
| Investments | | **-** | - | **637.1** | 689.4 |
| Financial asset | 9 | **-** | 45.0 | **-** | - |
| Other receivables | | **29.5** | 24.6 | **-** | - |
| | | **1,001.5** | 1,068.7 | **637.9** | 690.4 |
| **Current assets** | | | | | |
| Inventories | | **3.1** | 6.1 | **-** | - |
| Trade and other receivables | | **19.5** | 39.6 | **0.9** | 0.6 |
| Tax receivables | | **0.7** | 1.1 | **0.3** | 0.5 |
| Financial asset | | **52.7** | - | **-** | - |
| Liquid investments | | **-** | 40.2 | **-** | - |
| Cash and cash equivalents | | **103.6** | 126.2 | **0.2** | 0.2 |
| | | **179.6** | 213.2 | **1.4** | 1.3 |
| **Total assets** | | **1,181.1** | 1,281.9 | **639.3** | 691.7 |
| **Current liabilities** | | | | | |
| Trade and other payables | | **(37.2)** | (43.9) | **(3.0)** | (2.2) |
| Tax payable | | **(7.8)** | (11.6) | **(0.8)** | (0.2) |
| | | **(45.0)** | (55.5) | **(3.8)** | (2.4) |
| **Net current assets (liabilities)** | | **134.6** | 157.7 | **(2.4)** | (1.1) |
| **Non-current liabilities** | | | | | |
| Deferred tax liabilities | | **(183.7)** | (200.2) | **-** | - |
| Long term provisions | | **(59.9)** | (51.1) | **-** | - |
| | | **(243.6)** | (251.3) | **-** | **-** |
| **Total liabilities** | | **(288.6)** | (306.8) | **(3.8)** | (2.4) |
| **Net assets** | | **892.5** | 975.1 | **635.5** | 689.3 |
| **Equity** | | | | | |
| Share capital | | **27.6** | 27.6 | **27.6** | 27.6 |
| Other reserves | | **242.3** | 239.5 | **195.3** | 195.0 |
| Retained earnings | | **622.6** | 708.0 | **412.6** | 466.7 |
| **Total equity** | | **892.5** | 975.1 | **635.5** | 689.3 |

## Statements of Changes in Equity

for the year to 31 December 2015

**Group**

| | Called up share capital $ million | Share premium account $ million | Other reserves $ million | Retained earnings $ million | Total $ million |
|---|---|---|---|---|---|
| As at 1 January 2014 | 27.6 | 11.1 | 226.5 | 815.6 | 1,080.8 |
| Distributions | - | - | - | (118.1) | (118.1) |
| New shares issued | - | 0.1 | - | - | 0.1 |
| Issue and redemption of B shares | - | (11.2) | 11.2 | - | - |
| Share-based payments | - | - | 0.4 | - | 0.4 |
| Transfer relating to share-based payments | - | - | 1.7 | (1.7) | - |
| Unrealised currency translation differences | - | - | (0.3) | (1.8) | (2.1) |
| Retained profit for the year | - | - | - | 14.0 | 14.0 |
| As at 1 January 2015 | **27.6** | **-** | **239.5** | **708.0** | **975.1** |
| Distributions | **-** | **-** | **-** | **(51.1)** | **(51.1)** |
| Share-based payments | **-** | **-** | **0.5** | **-** | **0.5** |
| Transfer relating to share-based payments | **-** | **-** | **2.3** | **(2.3)** | **-** |
| Unrealised currency translation differences | **-** | **-** | **-** | **1.8** | **1.8** |
| Loss for the year | **-** | **-** | **-** | **(33.8)** | **(33.8)** |
| **As at 31 December 2015** | **27.6** | **-** | **242.3** | **622.6** | **892.5** |

**Company**

| | Called up share capital $ million | Share premium account $ million | Other reserves $ million | Retained earnings $ million | Total $ million |
|---|---|---|---|---|---|
| As at 1 January 2014 | 27.6 | 11.1 | 183.1 | 663.4 | 885.2 |
| Distributions | - | - | - | (119.2) | (119.2) |
| New shares issued | - | 0.1 | - | - | 0.1 |
| Issue and redemption of B shares | - | (11.2) | 11.2 | - | - |
| Share-based payments | - | - | 0.4 | - | 0.4 |
| Transfer relating to share-based payments | - | - | 0.6 | (1.7) | (1.1) |
| Unrealised currency translation differences | - | - | (0.3) | (53.9) | (54.2) |
| Loss for the year | - | - | - | (21.9) | (21.9) |
| As at 1 January 2015 | **27.6** | **-** | **195.0** | **466.7** | **689.3** |
| Distributions | **-** | **-** | **-** | **(51.1)** | **(51.1)** |
| Share-based payments | **-** | **-** | **0.5** | **-** | **0.5** |
| Transfer relating to share-based payments | **-** | **-** | **(0.1)** | **(2.3)** | **(2.4)** |
| Unrealised currency translation differences | **-** | **-** | **(0.1)** | **(31.5)** | **(31.6)** |
| Retained profit for the year | **-** | **-** | **-** | **30.8** | **30.8** |
| **As at 31 December 2015** | **27.6** | **-** | **195.3** | **412.6** | **635.5** |

## Cash Flow Statements

for the year to 31 December 2015

| | Notes | Group | | Company | |
|---|---|---|---|---|---|
| | | **2015** | 2014 | **2015** | 2014 |
| | | **$ million** | $ million | **$ million** | $ million |
| **Net cash from (used in) operating activities** | 11 | **80.3** | 251.2 | **(6.5)** | (6.8) |
| **Investing activities** | | | | | |
| Purchase of intangible assets | | **(17.5)** | (77.0) | **-** | - |
| Purchase of property, plant and equipment | | **(70.0)** | (85.5) | **(0.1)** | (0.2) |
| Decrease in liquid investments [1] | | **40.2** | 39.9 | **-** | - |
| Payment to abandonment fund | | **(4.9)** | (9.6) | **-** | - |
| Investment in subsidiary undertakings | | **-** | - | **(5.7)** | 0.9 |
| Dividends received from subsidiary undertakings | | **-** | - | **62.5** | 130.0 |
| **Net cash (used in) from investing activities** | | **(52.2)** | (132.2) | **56.7** | 130.7 |
| **Financing activities** | | | | | |
| Share-based payments | | **(1.0)** | (1.2) | **(1.0)** | (1.2) |
| Distributions | 10 | **(51.1)** | (118.1) | **(51.1)** | (119.2) |
| Proceeds on issue of ordinary share capital | | **-** | 0.1 | **-** | 0.1 |
| **Net cash used in financing activities** | | **(52.1)** | (119.2) | **(52.1)** | (120.3) |
| **Net (decrease) increase in cash and cash equivalents** | | **(24.0)** | (0.2) | **(1.9)** | 3.6 |
| **Cash and cash equivalents at beginning of year** | | **126.2** | 129.9 | **0.2** | 0.3 |
| Effect of foreign exchange rate changes | | **1.4** | (3.5) | **1.9** | (3.7) |
| **Cash and cash equivalents at end of year [1]** | | **103.6** | 126.2 | **0.2** | 0.2 |

[1] Liquid investment's 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 2015 was $103.6m (2014: $166.4m).

# 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 2015 or 2014, but is derived from those accounts. A copy of the statutory accounts for 2014 has been delivered to the Registrar of Companies and those for 2015 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 Basis of preparation**
The financial information has been prepared in accordance with the recognition and measurement criteria 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 Critical judgements and accounting estimates**
**Oil and gas reserves and DD&A**
Proven and probable reserves are estimated using standard recognised evaluation techniques. The estimates are reviewed at least twice a year and were audited at 31 December 2015. Future development costs are estimated taking into account the level of development required to produce the reserves by reference to operators, where applicable, and internal engineers. As discussed in the Review of Operations, the TGT and CNV proved and probable reserves estimates have been revised based on ongoing work of ERCE and audited by our reserves auditors, GCA. DD&A on CNV is expected to decrease on a per barrel basis to reflect the revised production and expenditure profiles from 2016 and DD&A on TGT will increase slightly as a result of a small decrease in 2P reserves. Reserves estimates are inherently uncertain, especially in the early stages of a field's life, and are routinely revised over the producing lives of oil and gas fields as new information becomes available and as economic conditions evolve. Such revisions may impact the Group's future financial position and results, in particular, in relation to DD&A and impairment testing of oil and gas property plant and equipment.

**Oil and gas assets**
Management considers intangible exploration and evaluation assets and tangible property, plant and equipment assets for impairment at least annually with reference to indicators in IFRS 6 and IAS 36, respectively. Note 7 describes the exploration expense of intangible exploration and evaluation assets during 2015 and Note 8 describes the impairment testing of property, plant and equipment also during 2015. Management considers the appropriateness of asset classification at least annually.

**Financial asset**
The key estimates that are used in calculating the fair value of the Group's financial asset arising on the disposal of its Mongolia interest are described in note 9 and are reviewed at least annually.

**4 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.

| | | | | **2015** |
|---|---|---|---|---|
| | **SE Asia $ million** | **Africa [2] $ million** | **Unallocated $ million** | **Group $ million** |
| Oil and gas sales | **214.8** | **-** | **-** | **214.8** |
| Depletion and depreciation | **99.0** | **-** | **0.2** | **99.2** |
| Exploration expense | **0.6** | **35.0** | **-** | **35.6** |
| Profit (loss) before tax [1] | **46.3** | **(35.8)** | **(2.3)** | **8.2** |
| Tax charge (see Note 5) | **42.2** | **-** | **(0.2)** | **42.0** |

| | 2014 | | | |
|---|---|---|---|---|
| | SE Asia<br>$ million | Africa [2]<br>$ million | Unallocated<br>$ million | Group<br>$ million |
| Oil and gas sales | 448.2 | - | - | 448.2 |
| Depletion and depreciation | 50.1 | - | 0.1 | 50.2 |
| Exploration expense | 0.3 | 79.2 | - | 79.5 |
| Impairment of property plant and equipment | 60.5 | - | - | 60.5 |
| Profit (loss) before tax [1] | 241.5 | (79.2) | (9.6) | 152.7 |
| Tax charge | 138.1 | - | 0.6 | 138.7 |

[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] Costs associated with the Africa segment are capitalised in accordance with the Group's accounting policy to the extent they are recoverable.

Included in revenues arising from South East Asia are revenues of $188.2m (2014: $234.5m and $194.4m) which arose from the Group's largest individual customers who have contributed 10% or more to the Group's revenue.

**Geographical information**

Group revenue and non-current assets (excluding the financial asset and 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 revenue is derived from foreign countries. The Group's revenue by geographical location is determined by reference to the final destination of oil or gas sold.

| | **2015**<br>**$ million** | 2014<br>$ million |
|---|---|---|
| Vietnam | **192.4** | 240.0 |
| China | **9.3** | 97.8 |
| Australia | **7.7** | 48.1 |
| Malaysia | **-** | 35.5 |
| Other | **5.4** | 26.8 |
| | **214.8** | 448.2 |

***Non-current assets***

| | **2015**<br>**$ million** | 2014<br>$ million |
|---|---|---|
| United Kingdom | **0.8** | 1.0 |
| Vietnam | **760.7** | 789.0 |
| Congo | **157.7** | 147.1 |
| Other - Africa | **52.8** | 62.0 |
| | **972.0** | 999.1 |

Excludes the financial asset and other receivables.

**5 Tax**

| | 2015 | 2014 |
|---|---|---|
| | **$ million** | $ million |
| Current tax | **58.5** | 122.7 |
| Deferred tax | **(16.5)** | 16.0 |
| | **42.0** | 138.7 |

The Group's corporation tax is calculated at 50% (2014: 50%) of the estimated assessable profit for the year in Vietnam. During 2015 and 2014 both current and deferred taxation have arisen in overseas jurisdictions only.

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

| | 2015 | 2014 |
|---|---|---|
| | **$ million** | $ million |
| Profit before tax | **8.2** | 152.7 |
| | | |
| Profit before tax at 50% (2014: 50%) | **4.1** | 76.4 |
| | | |
| Effects of: | | |
| Non-taxable income | **(4.1)** | - |
| Non-deductible expenses | **19.5** | 18.1 |
| Tax losses not recognised | **3.8** | 3.9 |
| Non-deductible exploration costs written off | **18.2** | 39.7 |
| Adjustments to tax charge in respect of previous years | **0.5** | 0.6 |
| **Tax charge for the year** | **42.0** | 138.7 |

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.

**6 (Loss) earnings per share**

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

| | 2015 | 2014 |
|---|---|---|
| | **$ million** | $ million |
| Earnings for the purposes of basic and diluted earnings per share | **(33.8)** | 14.0 |
| Effect of dilutive potential ordinary shares – Share awards and options | **(0.2)** | - |
| Earnings for the purposes of diluted earnings per share | **(34.0)** | 14.0 |

| | **Number of shares (million)** | |
|---|---|---|
| | **2015** | 2014 |
| Weighted average number of ordinary shares for the purpose of basic earnings per share | **329.1** | 328.6 |
| Effect of dilutive potential ordinary shares - Share awards and options | **3.7** | 1.3 |
| Weighted average number of ordinary shares for the purpose of diluted earnings per share | **332.8** | 329.9 |

In accordance with IAS 33 “Earnings per Share”, the effects of antidilutive potential have not been included when calculating dilutive loss per share for the year ended 31 December 2015.

**7 Intangible assets**
During 2015, exploration costs including costs associated with the MPS licence (2014: Albertine Graben Block V in eastern DRC) and costs associated with the early stages of new ventures in the amount of $13.1m (2014: $73.6m), were written off in the income statement in accordance with the Group's accounting policy on oil and gas exploration and evaluation expenditure. In accordance with IAS 37, a further $22.5m (2014: $5.9m on Block V) has been provided for respect of fulfilling our MPS licence commitments.

**8 Property, plant and equipment**
As discussed in the Review of Operations, CNV proved and probable oil and gas reserves audited by GCA have increased (2014: decreased). The increase in reserves offset the impact of the lower oil prices. 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 the fair value is derived from a discounted cash flow valuation of the 2P production profile, with a minor portion derived from the incremental value of 2C Contingent Resources, significantly risk adjusted. The key assumptions to which the fair value measurement is most sensitive are oil price, reserves and the risked value ascribed to Contingent Resources. With the increase in reserves on the CNV asset a test for impairment reversal loss was triggered. Management concluded that the carrying amount, net of the impairment recorded in 2014, remains within the reasonable range of fair value estimates for CNV and thus no significant reversal of the previously recognised impairment is considered to have risen in the year (2014: pre-tax impairment charge $60.5m and associated tax credit of $22.3m). As at 31 December 2015, the fair value of the asset is estimated based on a project specific discount rate of 12.5% (2014: 10%) and an oil price reflecting a gradual increase over five years from $45/bbl in 2016 (2014: three year forward curve) to $78/bbl (2014: $90/bbl) in 2020 plus inflation of 2.0% (2014: 2.5%) thereafter.

The sustained low oil price also triggered an impairment test on the Group's TGT asset in Vietnam. The recoverable amount of the TGT 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 the fair value is derived from a discounted cash flow valuation of the 2P production profile, with a portion derived from the incremental value of 2C Contingent Resources, risk adjusted. The key assumptions to which the fair value measurement is most sensitive are oil price, reserves and the risked value ascribed to Contingent Resources. As at 31 December 2015, the fair value of the asset is estimated to be higher than the book value based on a project specific discount rate of 10% (2014: 10%) and an oil price reflecting a gradual increase over five years from $45/bbl in 2016 (2014: three year forward curve) to $78/bbl (2014: $90/bbl) in 2020 plus inflation of 2.0% (2014: 2.5%) thereafter.

**9 Financial asset**
In 2005, the Group disposed of its Mongolia interest to Daqing Oilfield Limited Company. Under the terms of the transaction the Group is entitled to receive a subsequent payment amount of up to $52.7m, once cumulative production reaches 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 has notified SOCO that the production threshold of crude oil in excess of 27.8 million barrels was achieved in December 2015 resulting in a portion of the financial asset falling due post year end. The first payment, which has now become due, has not yet been received, however based on the correspondence with Daqing and legal advice received by the Company, the Directors believe that the full subsequent payment amount will be settled within the year.

At budgeted oil prices for 2016 and based on ongoing correspondence with the counter party, we project that the deferred payment of $52.7m associated with the 2005 sale of our Mongolian interests to be fully received in the next 12 months.

The subsequent payment amount was reclassified from non-current assets to current assets as a financial asset at fair value through profit or loss. The fair value of the subsequent payment amount was determined using a valuation technique as there is no active market against which direct comparisons can be made (Level 3 as defined in IFRS 7). Assumptions made in calculating the fair value at each reporting date include factors mentioned above, risked as appropriate, with the resultant cash flows discounted at a commercial risk free interest rate. The fair value of the financial asset at the date of completion of the sale in 2005 was $31.5 million. As at 31 December 2015, taking into account the achievement of the 27.8m barrel threshold in the year and the other factors described above, the Directors estimated that the fair value was $52.7 million (2014: $45.0 million) being the full subsequent payment amount due without risk adjustment**.**

**10 Distribution to Shareholders**
In June 2015, the Company paid a dividend to shareholders of $51.1m (£0.10 per share). The Trust, which is consolidated within the Group, waived its rights to receive a dividend.

The Board is recommending a final dividend of 2 pence per Ordinary Share, which amounts to approximately $9.5m. The proposed final dividend is subject to approval by shareholders at the Annual General Meeting and has not been included as a liability in these financial statements. The proposed dividend will be paid on 17 June 2016 to shareholders on the Register of Members at the close of business on 27 May 2016.

In October 2014, a return of value was made to all shareholders of the Company amounting to $119.2m (£0.22 per share) in cash by way of a B/C share scheme, which gave shareholders (other than certain overseas shareholders) a choice between receiving cash in the form of income or in the form of capital. As part of the B/C share scheme, 107,078,451 B shares, with a par value of £0.22 per share, were allotted and subsequently redeemed at par value. A further 224,876,192 C shares, with a par value of £0.0000001 per share, were allotted on which a dividend of £0.22 per share was paid, the C shares were then automatically reclassified as deferred shares.

The B shares were issued charging £11.2m to the share premium account and $27.2m to merger reserve, the redemption of the B shares resulting in a transfer of $38.4m to the capital redemption reserve. The C shares were issued out of merger reserve.

The Trust was allotted 3,294,111 B shares which were subsequently redeemed for $1.1m.

**11 Reconciliation of operating profit to operating cash flows**

| | Group | | Company | |
|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 |
| | **$ million** | $ million | **$ million** | $ million |
| Operating profit (loss) | **2.0** | 152.6 | **(9.7)** | (10.9) |
| Share-based payments | **1.5** | 1.6 | **1.5** | 1.6 |
| Depletion and depreciation | **99.2** | 50.2 | **0.2** | 0.1 |
| Impairment of property, plant and equipment (see Note 8) | **-** | 60.5 | **-** | - |
| Exploration expense (see Note 7) | **35.6** | 79.5 | **-** | - |
| **Operating cash flows before movements in working capital** | **138.3** | 344.4 | **(8.0)** | (9.2) |
| Decrease in inventories | **3.0** | 1.2 | **-** | - |
| Decrease (increase) in receivables | **12.4** | 32.1 | **(0.1)** | (0.1) |
| (Decrease) increase in payables | **(11.4)** | 4.3 | **1.5** | 2.4 |
| **Cash generated by (used in) operations** | **142.3** | 382.0 | **(6.6)** | (6.9) |
| Interest received | **0.5** | 0.7 | **0.1** | 0.1 |
| Interest paid | **(0.1)** | (0.2) | **-** | - |
| Income taxes paid | **(62.4)** | (131.3) | **-** | - |
| **Net cash from (used in) operating activities** | **80.3** | 251.2 | **(6.5)** | (6.8) |

Cash is generated from continuing operating activities only.

Cash and cash equivalents (which are presented as a single class of asset on the balance sheet) comprise cash at bank and other short term highly liquid investments that are readily convertible to a known amount of cash and which are subject to an insignificant risk of change in value.

**12 Events after the balance sheet date**

On 26 February 2016 we announced that the Baobab Marine-1 commitment well drilled in the Mer Profonde Sud Block, located in the Lower Congo Basin, offshore the Republic of Congo did not encounter hydrocarbons. The well was subsequently plugged and abandoned. A provision of $22.5m was made as at 31 December 2015 in relation to the cost of fulfilling the MPS licence commitments, including the Baobab Marine-1 commitment well.

**13 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 will be posted to shareholders in due course.