4 April 2017

VOLGA GAS PLC
Preliminary results for the year ended 31 December 2016

Volga Gas plc ("Volga Gas", the "Group" or the "Company"), the oil and gas exploration and production group operating in the Volga region of Russia, is pleased to announce its preliminary unaudited annual results for the year ended 31 December 2016.

During 2016, the Group's operational and financial performance dramatically improved in comparison with 2015, nearly doubling its oil, gas and condensate production and revenues while achieving a return to profitability and a significant strengthening of its financial position. While the recovery in oil prices and the Russian Ruble during 2016 were clearly beneficial, the main driver was in the performance of the Group's assets. In addition, the commencement of exports of condensate enabled production to continue uninterrupted through the year.

The successful drilling on the Vostochny Makarovskoye field in 2015 and the workovers on the Uzen oil field early in 2016 allowed average production from the Group's fields to rise by 99% to 6,507 barrels of oil equivalent per day ("boepd") (2015: 3,278 boepd), while in December 2016 total production averaged 8,060 boepd.

FINANCIALRESULTS

- Gross revenues up 122% to US$39.4 million (2015: US$17.8 million).
- Netback revenues (after export taxes and transport costs) were up 102% to US$35.4 million (2015: 17.5 million).
- Ten-fold increase in EBITDA to US$9.6 million (2015: US$0.9 million).
- Profit before tax of US$1.9 million (2015: loss of US$4.6 million), after abnormal operating expenses of US$1.8 million (2015: 3.4 million)
- Net cash flow from operations of US$13.0 million (2015: US$1.2 million).
- Total cash, net of borrowings, rose to US$15.8 million as at 31 December 2016 (31 December 2015: US$6.8 million) after utilising US$4.6 million for capital expenditure (2015: US$8.7 million). Total borrowings, comprising bank debt, at 31 December 2016 were US$3.9 million (2015: nil).
- Resuming distributions to shareholders with a total of US$0.062 per share of dividends proposed.

PRODUCTION & DEVELOPMENT

- Group average production in 2016 increased 99% to 6,507 boepd (2015: 3,278 boepd) and the average rate for December 2016 was a record, since surpassed in 2017, of 8,060 boepd.
- Production from VM and Dobrinskoye fields doubled to 5,801 boepd in 2016 (2015: 2,876 boepd). Increased well capacity following successful development drilling and largely uninterrupted production were the key drivers.
- During 2016 48% of condensate sales were exported (2015: 2%), an initiative started at the end of 2015. While the netback was less than for domestic sales as a result of having to cover export taxes and transportation costs, this strategy has enabled production to continue during periods when the local market is less active.
- Successful workovers and the installation of submersible pumps in the Uzen field enabled a 69% increase in production from the mature Uzen field to 706 bopd (2015: 418 bopd)

DOBRINSKOYE GAS PLANT

- Following the completion of the final stages of the upgrade project, the normal throughput levels of the Dobrinskoye gas plant was increased in mid 2016 from 750,000 m^3/d (26.5 mmcf/d) to 1 million m^3/d (35.3 mmcf/d).
- Progress has been made for significant reductions in costs by adopting new gas sweetening processes and more efficient disposal of waste materials.

Completed plans for LPG extraction. Construction of the LPG modules is to commence in mid-2017.

CURRENT TRADING AND OUTLOOK

- Since January 2017, normal production has been sustained at higher levels. During January and February 2017, production averaged, over 8,100 boepd. However, during March 2017 production was impacted by planned gas plant maintenance and seasonal disruption to oil deliveries so the average for January to March 2017 was 7,245 boepd.

- Oil prices and the Russian Ruble have been relatively stable during the first three months of 2017. In the current environment, the Group expects to improve on the financial performance of 2016.
- With two significant revenue-enhancing projects planned for 2017: the LPG unit at the gas processing plant and the Uzen horizontal well, capital expenditure in 2017 is expected to total US$12.3 million and will be key drivers for production growth in 2017.
- Recently completed independent reserve report confirmed a 2.4% increase in Proved and Probable reserves but a 10.8% reduction in Proved reserves.

Andrey Zozulya, Chief Executive of Volga Gas, commented:

"We have been really pleased with the sound performance of Volga Gas main producing assets in 2016 and with the solid improvements in the financial performance and position of the Group. Management looks forward to delivering higher production in 2017 than in 2016 and to achieving our targets to improve the profitability and sustainability of our business for the longer term and to delivering growing returns for our shareholders.

“I remain excited about the Group’s assets and remain positive about the potential for growth, both in reserves and production from our licences. We will also continue to seek value accretive opportunities, beyond our existing licence areas, building a focused exploration and production business.”

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Editors’ notes:
Volga Gas is an independent oil and gas exploration and production company operating in the Volga region of European Russia. The Company has 100% interests in its four licence areas. The information contained in this announcement has been reviewed and verified by Mr. Andrey Zozulya, Director and Chief Executive Officer of Volga Gas plc, for the purposes of the Guidance Note for Mining, Oil and Gas companies issued by the London Stock Exchange in June 2009. Mr. Andrey Zozulya has a degree in Geophysics and Engineering from the Groznensky Oil & Gas Institute and is a member of the Society of Petroleum Engineers.

Availability of report and accounts and investor presentation

The Group's full report and accounts and the notice of the annual general meeting of the Company will be dispatched to shareholders as soon as is practicable. Copies will also be available on the Company's website www.volgagas.com and on request from the Company at, 40 Dukes Place, London EC3A 7NH. The latest presentation for investors is also available on the Company’s website.

Glossary

Bpd/ Bopd	Barrels per day /Barrels of oil per day
Boepd	Barrels of oil equivalent per day, in which 6,000 cubic feet of natural gas is equated to one barrel of oil
mcm	thousands of standard cubic metres
mcm/d	thousands of standard cubic metres per day
mmcf/d	millions of standard cubic feet per day

Chairman's Statement

Dear Shareholder,

In spite of continuing challenging conditions experienced by the oil and gas industry worldwide and for Russia generally, 2016 has been a successful year for Volga Gas. Production has recovered from the reverses seen in 2015 and has been at the highest rate in the Group's ten year history. Revenues have more than doubled compared to 2015 and underlying profitability has been restored. Oil prices, that started 2016 at levels not seen for over 10 years have recovered substantially, doubling from the low point seen in January. The Russian Ruble has also had a similar though less marked recovery against the US dollar.

On an operational level, the results of 2016 were better than anticipated by management. Having successfully concluded the development drilling on the Vostochny Makarovskoye ("VM") field in 2015, this field, the Group's principal producing asset, has been operating at close to the planned plateau production rate of one million cubic metres per day of gas plus associated condensate for most of the second half of 2016. This production is the core of stable production which provides the main cash generation engine for the Group. In addition, workover activity conducted during early 2016 enabled a significant recovery in oil production from the Uzen oil field such that the production rate in 2016 was more than twice the level budgeted by management at the start of the year, even though the contribution to the Group's total output from this field is modest.

The results of 2016 have also been enhanced by some important commercial initiatives undertaken by management, notably the commencement of export sales of condensate, and more recently of some oil, to customers in the Baltic states neighbouring Russia. While the netback realisations on export sales, after taking into account export taxes and transport costs are slightly lower than for domestic sales, exports have enabled production to be maintained during periods in which the local domestic market is less active. There have also been several cost reduction initiatives, individually not significant, but which have enabled overall production costs to be lower than budgeted.

As a result of these developments, profitability and cash generation has increased materially during 2016.

Capital expenditure in 2016 has been modest as the Board decided to restrain spending while the oil price was low as it was at the start of the year. Such expenditure that has been undertaken was directed towards maintenance of the core assets and to projects able to provide immediate enhancements to the profitability. Consequently the net cash position has increased by US$9.7 million since the start of 2016.

The key strategic development under way is the further enhancement of the existing gas processing facilities, first to introduce a more efficient process for the sweetening of the gas and secondly to capture for sale the liquid petroleum gases ("LPG") that are currently vented and flared. The former is intended to achieve significant cost savings and enable higher production rates of over one million cubic metres per day of gas, while the latter will provide an additional and potentially highly profitable product stream. While these projects were first considered in 2015, further work undertaken in 2016 has enabled modifications to the plans which will enable the same results to be delivered at significantly lower capital expenditure than originally contemplated. The Chief Executive's Report covers both the work undertaken during the year on this and the plans to be implemented in 2017.

While the immediate outlook is more positive than it was a year ago, the finances of the Group will continue to be conservatively managed. Capital investment will continue to be at a modest level and focused on enhancing the profits from the gas and condensate production and on developing the proven oil reserves of the company.

The Group holds significant reserves in its three principal fields, confirmed in the recently completed independent report detailed below in the Operational Review by our Chief Executive Officer. These reserves form the basis of sustainable production with growth potential in the near term. These assets provide a platform for the Group to grow in the future, both through successful exploration and by selective value accretive acquisitions. The Board believes that Volga Gas has a strong asset base and the financial and operational capability to develop and extend these assets to provide long-term value growth for our shareholders. Meanwhile, in recognition of the strong financial position of the Group and the confidence in the continued and sustainable profitability, the Board has decided to resume payment of dividends to shareholders. The Board is recommending total dividends of US$0.062per Ordinary Share, comprising US$0.007 per ordinary share in respect of the profits generated in the year ended 31 December 2016 and a special dividend of US$0.055 per ordinary share.

Mikhail Ivanov
Chairman

Chief Executive's Report

As the Chairman has noted, Volga Gas achieved a significant improvement in its operational and financial performances in 2016 compared to 2015 with overall production increased by 99%, revenues up by 121% in US dollar terms and a return to profitability. Some of this was a result of the recovery in oil prices that took place steadily through the year, but much of this was as a result of the successful drilling and well workover activity that took place during 2015 and early in 2016, as well as the efficiency improvements implemented early in 2016.

The main driver of the performance was the Vostochny Makarovskoye ("VM") field on which we successfully concluded development drilling towards the end of 2015. With the necessary well capacity available through the year and having completed the required upgrades to the gas plant, we were able to produce at the full plateau rate of 1 million m^3 per day (35.3 mmcf/d) of gas plus associated condensate for much of the second half of 2016 – apart from periods of planned plant maintenance and for testing of potential new gas sweetening processes, described further below.
Another important factor in the production performance of 2016 was the commencement of exports of condensate. During 2015, there were periods in which the regional domestic market was unable to take our condensate leading to shut-ins at various periods. With the development of export channels, such market disruptions as occurred during 2016 had little or no impact on our ability to continue to sell condensate and therefore keep production going for the full year.

Another factor in the Group's overall production in 2016 was the recovery in oil production from the mature Uzenskoye field. Workovers on existing producing wells done in April and May 2016 led to a 160% increase in daily production rates from this field. Although this was still a minor part of the Group total, it made a useful contribution to the profit recovery of the Group.

In line with the Board's financial strategy at the start of 2016, committed capital investment was kept to the minimum levels in 2016. Nevertheless, the technical teams continued to work on projects that are expected to have material positive impact on the short and medium term performance of Volga Gas. These include new wells on the Uzenskoye field to develop the proven but undeveloped Albian reservoir in the field and projects that would significantly improve the output and efficiency of the Dobrinskoye gas processing plant and with significant reductions in the required capital expenditure compared to earlier proposals.

2017 objectives and medium term strategy

Management has three key objectives in 2017 relating to the operation of the Gas Processing Plant:

- Introduction of a new gas sweetening process using the Redox process. It is expected that this can be achieved with only minor modifications to the existing process plant. This should lead to a significant reduction in the cost of chemicals consumed in the gas sweetening process and elimination of bulk waste which needs to be disposed of safely.

- Construction of additional modules for the capture, storage and sale of liquid petroleum gases ("LPGs") from the gas and condensate streams produced from the VM and Dobrinskoye fields. LPGs, primarily comprising propane and butane, are currently either included in the sales gas stream or flared. The LPG project will provide an additional product stream which is expected to increase total sales volumes by approximately 10% and to enhance profitability. The construction of the project is expected, subject to the necessary regulatory approvals, to commence during 2Q 2017 and be completed before the end of 2017. The capital investment in the project is estimated at US$4.0 million.

- Disposal of accumulated waste chemicals resulting from the current gas sweetening process. During 2016 a pilot project for disposal by injection into a disused gas well was undertaken. Management expects to receive regulatory approval for this operation to be undertaken for the waste accumulated on-site.

The other key objective for management in 2017 is the development of the currently undeveloped crude oil reserves in the shallow Albian reservoir in the Uzen oil field. A first horizontal well is to be drilled on the field during 2017. If successful, further wells may be drilled. The horizontal wells are expected to add up to 1,000 barrels per day of incremental oil production and to produce over 2 million barrels of oil over their economic lives.

Reserves update

A new independent reserve report has recently been completed. While the new reserve estimates result in a net reduction in Proved Reserves, there was an overall increase in Proven and Probable Reserves. Details are contained in the Operational Review below.

Current trading and outlook

Between January and March 2017, Group production averaged 7,245 barrels of oil equivalent per day, in line with management's plan. Production in March 2017 was impacted by planned maintenance and seasonal disruptions, after averaging over 8,100 boepd in January and February 2017. The gas plant is consistently operating at planned capacity of one million m^3 per day, with condensate output running at over 2,000 barrels per day, approximately half of which is being sold to export markets. International oil prices have maintained their higher levels reached in December 2016. Oil production is now a minor part of the Group's output and has suffered moderate disruption as the mild winter caused difficulties in collection of oil by our customers.

In the current environment, and at current production rates, management expects the Group's financial performance in 2017 to improve further on that of 2016. Meanwhile, new capital expenditure commitments remain within projected cash generation, permitting a resumption of a sustainable distribution policy for shareholders.

Andrey Zozulya
Chief Executive Officer

Operational Review

Operations overview

Group production in 2016, at an average daily rate of 6,507 boepd, was 99% higher than the 3,278 boepd achieved in 2015. Three were three reasons for this: higher production capacity from the VM field on which the new wells were put on production at the end of 2015, commencement of condensate exports which allowed production to remain uninterrupted during periods when the local domestic market was disrupted and, less materially but also positive, the recovery in oil production from the Uzen oil field.

Combined with a steady recovery in oil prices through the year and a rebound in the Ruble, netback revenues in US dollar terms increased by 102% compared to 2015, taking into account the export taxes and transportation costs associated with the exports of condensate. In addition, as a result of more accurate fiscal metering introduced at the start of 2016, the formula for calculating Mineral Extraction Tax charged on gas and condensate was reduced. This combined with various cost reduction measures contributed in a near 10-fold increase in EBITDA, which was US$9.6 million in 2016 compared to US$0.9 million in 2015 and enabled the Group to report a profit before tax of US$1.9 million (2015: loss before tax of US$4.6 million).

In addition to managing higher levels of production, much of the operational activity in 2016 was directed towards further enhancements to the gas plant processes, sustaining higher output from the gas and condensate fields and drilling of new horizontal wells on the Uzen oil field.

Gas/condensate production

The Dobrinskoye and VM fields are managed as a single business unit. Production from the fields is processed at the gas plant located next to the Dobrinskoye field, extracting the condensate and processing the gas to pipeline standards before input into Gazprom's regional pipeline system via an inlet located at the plant. During 2015 two production wells on the VM field, VM#3 and VM#4 were drilled. VM#4 was put on production during November 2015 while the completion and first production from the VM#3 well was deferred until spring of 2016 when the gas plant upgrades enabled the higher throughput rates to utilise its full capacity.

With a total of four wells in the principal reservoir, the Evlano Livinskiy carbonate, and a further well in the secondary Bobrikovskiy sandstone reservoir, management considers the VM field to be fully developed and capable of producing at the plateau rate of 1.0 mmcm/d (35.3 mmcf/d) with associated condensate of 2,000 bpd – a total of approximately 7,800 boepd.

During January and February 2015, and again during May and June 2015, production of gas and condensate had to be temporarily suspended since it was not possible to sell the condensate produced in the local market. (Gas and condensate are produced simultaneously from the wells and once the storage capacity at the gas plant is full, it is necessary to cease production.) At the end of 2015, however, Volga Gas commenced export sales of condensate and with this channel available it was possible to continue production steadily throughout 2016 in spite of similar market disruptions being experienced.

Production during 2016 averaged 25.5 mmcf/d of gas and 1,557 bpd of condensate (2015: 12.5 mmcf/d of gas and 784 bpd condensate) and overall increase of 103% in equivalent barrels of oil terms. Nevertheless, this production rate is below the full capacity of the existing wells as the gas processing plant's operations continue to be fine-tuned. This is covered in more detail below. However, during December 2016, the output averaged 32.2 mmcf/d of gas and 1,799 bpd of condensate, a total of 7,167 boepd, more closely reflecting management's estimate of the actual capabilities of the wells.

During 2016, gas continued to be sold to Trans Nafta under contract at a fixed Ruble contract gas sales price of RUR 4,201 per mcm which has been in force since July 2015. However, as of December 2016, a proportion of the gas sales have been made directly to Gazprom which has resulted in a modest increase in the net realisations. In US dollar terms, however, the recovery of the Ruble has led to the gas sales price rising from US$1.29/mcf in January to US$1.68/mcf in December. The average gas selling price for 2016 was US$1.51/mcf (2015: US$1.49).

Prior to late 2015 condensate was sold entirely into the local domestic market. However, with the periods of low domestic demand which impacted our business during 2015, channels for exporting condensate were developed and the first cargoes of condensate were sold to export customers in the Baltic region during November and December 2015. During 2016 approximately 48% of total sales of condensate were to export customers (2015: 2%).

During 2016 the average condensate netback price (after accounting for export taxes and transportation costs) US$24.83 per barrel (2015: US$23.89).

Average unit production costs on the gas-condensate fields increased moderately to US$5.19 per boe in 2016 (2015: US$5.06). The recovery in the Ruble, in which effectively all the costs are denominated and higher costs associated with chemicals consumed in gas processing and higher costs of waste disposal were partly offset by other cost savings.

Gas processing plant

During the first half of 2016, the Dobrinskoye gas processing plant was consistently operating at average rates of 750,000 m^3 per day (26.5 million cubic feet per day). Since August 2016, the flow rates from the gas fields were increased to test the capability of the plant to process at the planned higher rate of one million m^3/day (35.3 mmcf/d). As a result, management is confident that the gas plant is capable of sustained throughput at the rate of 35.3 mmcf/d. This was actually achieved in the month of December 2016.

While the physical process plant and pipelines were designed to operate at 1 million m^3 per day, the need to dispose of bulky spent chemicals used in gas sweetening remains a constraint on the operations.

During 2016, technical studies and tests were conducted of alternative sweetening chemical processes. As a result of these tests, management has decided that a switch to Redox based gas sweetening would be the optimal solution for the gas plant. The key advantage of this process is that the chemical used can be easily re-generated and re-used resulting in significantly lower chemicals costs and eliminating much of the bulk waste materials. The existing process units can be used for this with only minor modification. Full scale trials, of the Redox-based sweetening process are continuing through April 2017.

As announced on 29 November 2016, the Board has given preliminary authorisation to a project based at the Group's Dobrinskoye Gas Processing plant for the capture, storage and sale of LPG. LPGs, primarily comprising propane and butane, are currently either included in the sales gas stream or flared.

The LPG project will provide an additional product stream which is expected to increase total sales volumes by approximately 10% and to enhance profitability.

The construction of the project is expected, subject to the necessary regulatory approvals, to commence during 2Q 2017 and be completed before the end of 2017. The total capital investment in the project is estimated at US$5.0 million.

Oil production

The Uzen oil field has been producing oil from a cretaceous Aptian reservoir at a depth of approximately 1,000 metres since 2009. Until 2016 it produced under natural reservoir pressure drive. As the oil was produced, the oil-water contact in the reservoir rose and the wells at the edge of the field were shut in as water cut increased. Consequently by the start of 2016, production had declined to 300 bopd from three wells. During H1 2016 workovers were conducted on the producing wells to block off water inflow into the well bores and to install electrical submersible pumps to provide artificial lift on the wells. As a result of these activities, the ongoing oil production rate increased from approximately 450 bpd to over 850 bpd and these rates were sustained through the rest of 2016.

During November and December 2016, a sidetrack from the currently non-producing Uzen #4 well was being drilled with the intention of producing oil from a potentially bypassed "attic" in the Aptian reservoir. However, during the drilling of a deviated section from the existing vertical well, the drill bit and certain directional drilling tools supplied by Schlumberger became stuck in the well, as a result of a faulty pump interrupting drilling mud circulation. Various attempts were made to release the stuck drill bit but without success. Consequently the operation was suspended. Given the attractiveness of accessing incremental reserves in a side track well, Volga Gas will recommence drilling a sidetrack having appointed a new drilling contractor.

Volga Gas has, however, incurred costs of US$1.6 million primarily for replacement of the directional drilling tools belonging to Schlumberger.

There remain significant proved undeveloped reserves in the shallower Albian reservoir. Following a technical study carried out during 2015, management recommended a development plan for this reservoir would be to drill up to two horizontal production wells. The cost of each of these wells is currently estimated to be US$2.0 million and would expect to develop over 2 million barrels of reserves at a capital cost of $4.00 per barrel of reserves. The first horizontal well is to commence drilling as soon as Eurasia Drilling, the newly appointed contractor, has mobilised its rig onto the prepared location.

The Group's oil production, whilst of modest scale, has been very profitable for the Group and a useful contributor of cash flow. With successful development of the Albian reserves, this would become a more important contributor to future profitability.

Exploration

During 2016, as a result of the decision to minimise expenditures, exploration activity was confined to internal technical studies.

Nevertheless, the Group has identified a number of exploration targets in the Karpenskiy Licence Area at shallow horizons of between 1,000 and 2,000 metres depth. These provide low cost opportunities to add potentially material oil reserves. While management recognises the potential of these prospects, the immediate priority is to maximise the value and cash generation from proven resources.

The Group has fulfilled all its licence commitments on the Karpenskiy Licence Area and further drilling in the area is discretionary. Nevertheless future development of the oil potential in the Group's licences is a key element of management's medium-term strategy.

Oil, gas and condensate reserves as of 1 January 2017

In December 2016, Volga Gas commissioned an independent evaluation of the Group's oil, gas and condensate reserves. This has resulted in an overall reduction of Proved Reserves of 3.7 mmboe, or 10.8%, but an overall increase of 0.9 mmboe in Proved and Probable ("2P") Reserves, a 2.4% increase.

The principal changes to the reserve estimates arose from a downgrade in reserves from the Dobrinskoye field, accounting for a 3.5 mmboe reduction in Proved Reserves and of 2.7 mmboe in 2P Reserves. This was offset by increases in reserves at the Uzen field by 2.3 million barrels of Proved and 1.7 million barrels of 2P Reserves. On the VM field, there was a reduction of 2.8 mmboe in Proved Reserves but a net increase of 1.7 mmboe in 2P Reserves, reflecting a more conservative basis of estimation. Within the VM reserves, a proportion of gas reserves have been reclassified as LPG to reflect the fact that when LPG extraction takes place a proportion of gas currently sold down the pipeline will be converted into LPG.

The independent assessment of the reserves and net present value of future net revenue ("NPV") attributable to the Group's three principal fields, Dobrinskoye, Vostochny Makarovskoye and Uzenskoye, as at 31 December 2016, was prepared in accordance with reserve definitions set by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers ("SPE").

The following table shows the Proven and Probable reserves as at 31 December 2016 and changes from previous estimates.

Andrey Zozulya
Chief Executive Officer

Oil, gas and condensate reserves

	Oil & Condensate (mmbbl)	**Gas (bcf)**	**LPG (tonnes) (000)**	**Total (mmboe)**
As at 31 December 2015				
Proved reserves	12.989	142.6	-	36.698
Proved plus probable reserves	14.293	153.5	-	39.879
Production: 1 January -31 December 2016	0.828	9.3	-	2.382
Revisions to estimates:				
Proved reserves	(1.210)	(34.8)	277	(3.697)
Proved plus probable reserves	(1.312)	(12.7)	367	0.908
As at 31 December 2016				
Proved reserves	**10.951**	**98.5**	**277**	**30.619**
Proved plus probable reserves	**12.153**	**131.5**	**367**	**38.405**

Notes:

1. Volga Gas (through its wholly owned subsidiaries PGK and GNS) is the operator and has a 100% interest in four licences to explore for and produce oil, gas and condensate in the Volga region.
2. The reserve estimates as at 31 December 2016 were independently assessed by OOO Geostream Assets Management. The full reserve report is available on the Company's website: www.volgagas.com. The estimates at 31 December 2015 were based on the reserve evaluation conducted by Miller and Lents in 2012 adjusted for subsequent production.
3. The reserve estimates were prepared in metric units: tonnes for oil, condensate and LPG and standard cubic metres for gas. The conversion ratios from tonnes to barrels applied in the table above were 7.833 barrels per tonne of oil, 8.75 barrels per tonne of condensate and 11.75 barrels per tonne of LPG. One cubic metre equates to 35.3 cubic feet and one barrel of oil equivalent is given by 6,000 standard cubic feet of gas.
4. The above reserve estimates, prepared in accordance with reserve definitions prepared by the Oil and Gas Reserves Committee of the SPE, have been reviewed and verified by Mr Andrey Zozulya, Director and Chief Executive Officer of Volga Gas plc, for the purposes of the Guidance Note for Mining, Oil and Gas companies issued by the London Stock Exchange in June 2009. Mr Zozulya holds a degree in Geophysics and Engineering from the Groznensky Oil & Gas Institute and is a member of the Society of Petroleum Engineers.

Financial Review

Results for the year

In 2016, the Group generated US$39.4 million in turnover (2015: US$17.8 million) from the sale of 837,837 barrels of crude oil and condensate (2015: 438,910 barrels) and 9,210 million cubic feet of natural gas (2015: 4,545 million cubic feet).

The average price realised for liquids sold in the domestic market was the equivalent of US$30.59 per barrel (2015: US$25.16 per barrel). During 2016, approximately 48% of condensate sales were to export customers in the Baltic States (2015: 2%). Export sales incur export taxes and transportation costs, whereas for domestic sales the selling price is effectively a wellhead netback price. The average netback price for liquids sales, calculated by deducting selling expenses from revenue attributed to oil and condensate sales, in 2016 was US$25.70 (2015: US$24.43).

The gas sales price during 2016 averaged US$1.51 per thousand cubic feet (2015: US$1.49 per thousand cubic feet), the increase being entirely attributable to the movement in the Ruble/US dollar exchange rate. The sales price of gas in Rubles was unchanged in 2016 (increased by 8.1% in July 2015), although in December 2016 the company commenced sales directly to Gazprom which resulted in a small increase in realised price. Production activities generated a gross profit of US$13.1 million in 2016 (2015: US$2.2 million).

In 2016, the total cost of production increased to US$11.0 million (2015: US$7.4 million), with variable costs driven by higher production volumes, some Ruble inflation and the effect of the recovery in the Ruble on our predominantly Ruble denominated costs. Unit field operating costs fell to US$3.93 per boe (2015: US$5.03 per boe), partly as a result of fixed costs shared among higher volumes and partly from cost efficiencies. Production based taxes were US$10.3 million (2015: US$5.9 million) reflecting higher volumes and the impact of oil prices and Ruble exchange rates on Mineral Extraction Tax (“MET”) rates as well as the impact of further formula changes that came into effect on 1 January 2016. More accurate metering of unstabilised condensate enabled a relative reduction of volumes taxed. MET paid in 2016 represented 29% of netback revenues (2015: 35% of revenues). Operating and administrative expenses in 2016 were US$4.5 million (2014: US$3.4 million).

The Group experienced a ten-fold increase in EBITDA (defined as operating profit before non-cash charges, including exploration expense, depletion and depreciation) to US$9.6 million (2015: US$0.9 million).

Since the Group uses Proved reserves as a basis of calculation of the annual depletion charge, the unit rate of Depletion, Depreciation and Amortisation (“DD&A”) increased as a result of the 10.8% reduction in Proved reserves. This combined with the 99% increase in production led to a DD&A charge in 2016 of US$5.0 million (2015: US$2.4 million).

With exploration and evaluation expenses of US$0.3 million in 2016 (2015: US$0.6 million) and a provision of US$1.8 million for the write off of development assets, mainly arising from compensation payable in relation to the stuck hole in the Uzen#4 sidetrack (2015: US$3.0 million) the Group recorded an operating profit for 2016 of US$2.5 million (2015: operating loss of US$5.0 million).

Including net interest income of US$0.2 million (2015: US$0.1 million) and other net losses of US$0.8 million (2015: net gain of US$0.3 million), the Group recognised a profit before tax of US$1.9 million (2015: loss before tax of US$4.6 million) and reported net profit after tax of US$1.2 million (2015: net loss after tax of US$4.1 million) after a deferred tax charge of US$0.7 million (2014: deferred tax credit of US$0.6 million).

Cash flow

Group cash flow from operating activities was US$10.4 million (2015: US$1.2 million). Net working capital movements contributed cash inflow of US$2.7 million in 2016 (2015: US$0.8 million), which included movements in prepayments of US$1.9 million from export customers (2015: US$0.9 million). With lower capital expenditures in 2016, the net outflow from investing activities was US$4.6 million (2015: US$8.7 million). Net cash inflow from financing activities was US$3.6 million (2015: outflow of US$1.0 million).

Dividend

In July 2014, the Board announced the adoption of a policy to distribute approximately 50% of consolidated net profit after tax as a cash dividend. Dividends of US$0.05 per ordinary share were declared in respect of the year ended 31 December 2014. In light of the material reduction in the oil price, adverse financial conditions prevailing in Russia and the losses incurred, no dividends were paid in 2016. However, in recognition of the recovery in profitability and the financial position of the Group, the Board considers it an appropriate time to resume distributions. Consequently the Board is recommending a dividend of US$0.007 per ordinary Share in respect of 2016 and in addition a special dividend of US$0.055 per ordinary share, subject to approval at the Annual General Meeting on 19 May 2017.

Capital expenditure

During 2016 capital expenditure of US$4.2 million was incurred (2015: US$10.4 million), of which US$3.9 million was incurred on development and producing assets (2015: US$9.8 million) and US$0.3 million incurred on exploration (2015: US$0.6 million). Capital expenditure in 2016 includes final payments for drilling on the VM field, drilling and workovers on the Uzen oil field and upgrades to the gas processing plant.

Balance sheet and financing

As at 31 December 2016, the Group held cash and bank deposits of US$19.7 million (2015: US$6.8 million). All of the Group's cash balances are held in bank accounts in the UK and Russia and the majority of the Group's cash is held in US Dollars.

In December 2016, the Group drew down from a RUR 240 million (US$4.0 million) of bank facility, which is to be utilised to fund purchases of equipment for the LPG project. Total debt as at 31 December 2016 was US$4.0 million (2015: nil).

As at 31 December 2016, the Group's intangible assets increased to US$3.5 million (2015: US$2.9 million). Property, plant and equipment, increased to US$55.9 million (2015: US$48.3 million), primarily reflecting the impact of foreign exchange adjustments. The carrying values of the Group's assets relating to its main cash generating units have been subject to impairment testing. The result of the impairment tests, including sensitivity analysis around the central economic assumptions as detailed in Note 4(b) to the Accounts, showed no requirement for impairment, although as noted above there were impairments and write-offs relating to unsuccessful operations.

For the year ending 31 December 2016, the Group recorded a currency retranslation income of US$10.5 million (2015: expense of US$15.3 million) in its Other comprehensive income, relating to the movement of the Ruble against the US Dollar.

The Group's committed capital expenditures are less than expected cash flow from operations and cash-on-hand and such expenditures can be managed in light of the volatility in international oil prices and the Ruble. The Group may consider additional debt facilities to fund the longer-term development of its existing licences and operational facilities as appropriate.

The Group's financial statements are presented on a going concern basis.

Vadim Son
Chief Financial Officer

Five year financial and operational summary

Sales volumes	**2016**	**2015**	**2014**	**2013**	**2012**
Oil & condensate (barrels ‘000)	828	439	604	547	530
Gas (mcf)	9,320	4,545	5,671	3,128	1,193
Total (boe ‘000)	**2,381**	**1,196**	**1,549**	**1,068**	**728**

Operating Results (US$ 000)	**2016**	**2015**	**2014**	**2013**	**2012**
Oil and condensate sales	25,380	11,041	27,220	26,067	25,526
Gas sales	14,032	6,786	12,203	8,554	2,769
Revenue	**39,412**	**17,827**	**39,423**	**34,621**	**28,295**
Field operating costs	(9,367)	(6,016)	(7,805)	(5,946)	(3,776)
Production based taxes	(10,255)	(5,877)	(8,344)	(8,095)	(8,951)
Depletion, depreciation and amortisation	(5,037)	(2,345)	(4,656)	(2,611)	(2,280)
Other production expenses	(1,601)	(1,352)	(1,709)	(1,799)	(1,562)
Cost of sales	**(26,260)**	**(15,589)**	**(22,514)**	**(18,451)**	**(16,569)**
Gross profit	**13,152**	**2,238**	**16,909**	**16,170**	**11,726**
Selling expenses	(4,052)	(319)	-	-	-
Exploration expense	(265)	(635)	-	(2,519)	(8,475)
Write-off of development assets	(1,798)	(2,950)	-	(1,439)	(188)
Operating, administrative & other expenses	(4,526)	(3,377)	(4,157)	(4,029)	(8,969)
Operating profit/(loss)	**2,511**	**(5,043)**	**12,752**	**8,183**	**(5,906)**

Net realisation	**2016**	**2015**	**2014**	**2013**	**2012**
Oil & condensate (US$/barrel)	30.65	25.16	45.07	47.63	48.21
Oil & condensate netback (US$/barrel)	25.76	24.43	-	-	-
Gas (US$/mcf)	1.51	1.49	2.15	2.73	2.32

Operating data (US$/boe)	**2016**	**2015**	**2014**	**2013**	**2012**
Production and selling costs	3.93	5.03	5.04	5.56	5.18
Production based taxes	4.31	4.91	5.39	7.58	12.29
Depletion, depreciation and other	2.12	1.98	3.01	2.44	3.13

EBITDA calculation (US$ 000)	**2016**	**2015**	**2014**	**2013**	**2012**
Operating profit/(loss)	2,511	(5,043)	12,752	8,183	(5,906)
Exploration expense	265	635	-	2,519	8,475
DD&A and other non-cash expense	6,857	5,319	4,656	4,050	5,413
EBITDA	**9,634**	**911**	**17,408**	**14,752**	**7,982**
EBITDA per boe	4.05	0.76	11.24	13.81	10.96

Netback realisation for oil and condensate is calculated by deducting Selling expenses from Oil, gas and condensate sales.

Principal Risks and Uncertainties

The Group is subject to various risks relating to political, economic, legal, social, industry, business and financial conditions. The following risk factors, which are not exhaustive, are particularly relevant to the Group's business activities:

Volatility of oil prices

The supply, demand and prices for oil are influenced by factors beyond the Group's control. These factors include global and regional demand and supply, exchange rates, interest and inflation rates and political events. A significant prolonged decline in oil and gas prices could impact the profitability of the Group's activities.

All of the Group's revenues and cash flows come from the sale of oil, gas and condensate. If sales prices should fall below and remain below the Group's cost of production for any sustained period, the Group may experience losses and may be forced to curtail or suspend some or all of the Group's production, at the time such conditions exist. In addition, the Group would also have to assess the economic impact of low oil and gas prices on its ability to recover any losses the Group may incur during that period and on the Group's ability to maintain adequate reserves.

The Group does not currently hedge its crude oil production to reduce its exposure to oil price volatility as the structure of taxes applied to oil and condensate production in Russia effectively reduce the exposure to international market prices for oil. In addition, the Ruble exchange rate has tended to move with the oil price, reducing the overall volatility of oil prices when translated into Russian Rubles.

Market risks

The Group's revenues generated from oil and condensate production have typically been from sales to local domestic customers. There have been periods when the local market has been unable to purchase condensate, causing temporary suspension of production and loss of revenues. Since November 2015, the Group has been selling up to 50% of its condensate into regional export markets to mitigate this risk. Gas sales are made, via an intermediary, into the domestic market via the Gazprom pipeline network. In December 2016, the Group commenced sales of gas directly to Gazprom. The region in which the Group operates is reliant on external gas supplies. Consequently the risk of insufficient demand for the Group's gas is considered low. Gas sales have generally been conducted as expected, subject to occasional constraints during pipeline maintenance operations.

Oil and gas production taxes

The Group's sales generated from oil and gas production are subject to Mineral Extraction Taxes, which form a material proportion of the total costs of sales. The rates of these taxes are subject to changes by the Russian government. Changes to rates which come into effect during 2015 and in 2016 materially increased the rates on crude oil, condensate and natural gas. With oil prices at low levels and Russian Government budgets under pressure, there are risks of further adverse changes to production taxes.

Exploration and reserve risks

Whilst the Group will seek to apply the latest technology to assess exploration licences, the exploration for, and development of, hydrocarbons is speculative and involves a high degree of risk. These risks include the uncertainty that the Group will discover sufficient commercially exploitable oil or gas resources in unproven areas of its licences. Unsuccessful exploration efforts may result in impairment to the balance sheet value of exploration assets.

In December 2016, the Group commissioned a reserve evaluation based on reporting standards set by the Society of Petroleum Engineers. The revisions to the Group's reserve estimates are shown in the Operational Review on pages 7 and 8. If the actual results of producing the Group's fields are significantly different to expectations, there may be changes in the future estimates of reserves. These may impact the balance sheet carrying values of the Group's Property, Plant and Equipment.

Environmental risk

The oil and gas industry is subject to environmental hazards, such as oil spills, gas leaks, ruptures and discharges of petroleum products and hazardous substances, including waste materials generated by the sweetening process currently in use at the Dobrinskoye gas processing plant. These environmental hazards could expose the Group to material liabilities for property damages, personal injuries, or other environmental harm, including costs of investigating and remediating contaminated properties.

The Group is subject to stringent environmental laws in Russia with regards to its oil and gas operations. Failure to comply with such laws and regulations could subject the Group to material administrative, civil, or criminal penalties or other liabilities. Additionally, compliance with these laws may, from time to time, result in increased costs to the Group's operations, impact production, or increase the costs of potential acquisitions.

The Group liaises closely with the Federal Service of Environmental, Technological and Nuclear Resources of the Saratov and Volgograd Oblasts on potential environmental impact of its operations and conducts environmental studies both as required by, and in addition to, its licence obligations to mitigate any specific risk. The Group's operations are regularly subject to independent environmental audit.

The Group did not incur any material costs relating to the compliance with environmental laws during the period.

Risk of operating oil and gas properties

The oil and gas business involves certain operating hazards, such as well blowouts, cratering, explosions, uncontrollable flows of oil, gas or well fluids, fires, pollution and releases of toxic substances. Any of these operating hazards could cause serious injuries, fatalities, or property damage, which could expose the Group to liabilities. The settlement of these liabilities could materially impact the funds available for the exploration and development of the Group's oil and gas properties. The Group maintains insurance against many potential losses and liabilities arising from its operations in accordance with customary industry practices, but the Group's insurance coverage cannot protect it against all operational risks.

Foreign currency risk

The Group's capital expenditures and operating costs are predominantly in Russian Rubles ("RUR") while a minority of administrative expense is in US Dollars, Euros and Pounds Sterling. Revenues are predominantly received in RUR so the operating profitability is not materially exposed to moderate short-term exchange rate movements. The functional currency of the Group's operating subsidiaries is the RUR and the Group's assets and liabilities are predominantly RUR denominated. As the Group's presentational currency is the US Dollar, the significant devaluation of the RUR against the US Dollar negatively impacts the Group's financial statements.

Business in Russia

Amongst the risks that face the Group in conducting business and operations in Russia are:

- Economic instability, including in other countries or the global economy that could lead to consequences such as hyperinflation, currency fluctuations and a decline in per capita income in the Russian economy.
- Governmental and political instability that could disrupt, delay or curtail economic and regulatory reform, increase centralised authority or result in nationalisations.
- Social instability from any ethnic, religious, historical or other divisions that could lead to a rise in nationalism, social and political disturbances or conflict.
- Uncertainties in the developing legal and regulatory environment, including, but not limited to, conflicting laws, decrees and regulations applicable to the oil and gas industry and foreign investment.
- Unlawful or arbitrary action against the Group and its interests by the regulatory authorities, including the suspension or revocation of their oil or gas contracts, licences or permits or preferential treatment of their competitors.
- Lack of independence and experience of the judiciary, difficulty in enforcing court or arbitration decisions and governmental discretion in enforcing claims.
- Unexpected changes to the federal and local tax systems.
- Laws restricting foreign investment in the oil and gas industry.
- The imposition of sanctions upon certain entities in Russia.

The Group's operations and financial management have not to date been impacted directly by any sanctions.

Legal systems

Russia, and other countries in which the Group may transact business in the future, have or may have legal systems that are less well developed than those in the United Kingdom. This could result in risks such as:

- Potential difficulties in obtaining effective legal redress in the court of such jurisdictions, whether in respect of a breach of contract, law or regulation, including an ownership dispute.
- A higher degree of discretion on the part of governmental authorities.
- The lack of judicial or administrative guidance on interpreting applicable rules and regulations.
- Inconsistencies or conflicts between and within various laws, regulations, decrees, orders and resolutions.
- Relative inexperience of the judiciary and courts in such matters.

In certain jurisdictions, the commitment of local business people, government officials and agencies and the judicial system to abide by legal requirements and negotiated agreements may be more uncertain, creating particular concerns with respect to licences and agreements for business. These may be susceptible to revision or cancellation and legal redress may be uncertain or delayed. There can be no assurance that joint ventures, licences, licence applications or other legal arrangements will not be adversely affected by the jurisdictions in which the Group operates.

Liquidity risk

At 31 December 2016 the Group had US$19.7 million (2015: US$6.8 million) of cash and cash equivalents of which US$16.1 million was held in bank accounts in Russia (2015: $2.0 million). A significant proportion of the cash held in Russia is expected to be placed in the UK during 2017 ahead of proposed dividend payments. As at 31 December 2016, total bank debt was US$4.0 million (2015: nil). The Group has fully drawn on the debt facilities available as at 31 December 2016. The Group intends to fund its ongoing operations and development activities from its cash resources and cash generated by its established operations. At 31 December 2016 the Group has budgeted capital expenditures US$12.3 million of which US$4.0 million is allocated to the LPG project and US$5.7 million is for the Uzen horizontal well. There were approximately US$4.9 million of accounts payable relating to capital expenditures and other expenses incurred in the year ended 31 December 2016 (2015: US$1.5 million). The Board considers that the Group will have sufficient liquidity to meet its obligations after payment of proposed dividends of US$5.0 million. All current and planned capital expenditures are discretionary and may be deferred or cancelled in the light of the Group’s cash generation and liquidity position.

Through its ordinary course activities, the Group is exposed to legal, operational and development risk that could delay growth in its cash generation from operations or may require additional capital investment that could place increased burden on the Group’s available financial resources.

The Group is also exposed to fraudulent transfers of funds from its bank accounts. During the year ended 31 December 2015, the Group enhanced its protections and procedures after suffering such fraudulent transfers.

Capital risk

The Group manages capital to ensure that it is able to continue as a going concern whilst maximising the return to shareholders. The Group is not subject to any externally imposed capital requirements. The Board regularly monitors the future capital requirements of the Group, particularly in respect of its ongoing development programme. Management expects that the cash generated by the operating fields will be sufficient to sustain the Group’s operations and committed capital investment for the foreseeable future and has a policy of maintaining a minimum level of liquidity to cover forward obligations. Further short-term debt facilities may be arranged to provide financial headroom for future development activities.

Vadim Son
Chief Financial Officer

Abbreviated Financial Statements
for the year ended 31 December 2016

Group Income Statement
(presented in US$ 000)

Year ended 31 December	Notes	2016	2015
Revenue	4	39,412	17,827
Cost of sales	5	(26,260)	(15,589)
Gross profit		**13,152**	**2,238**
Selling expenses	5(a)	(4,052)	(319)
Operating and administrative expenses	5	(4,526)	(3,377)
Exploration and evaluation expense		(265)	(635)
Write off of development assets	5(b)	(1,798)	(2,950)
Operating profit/(loss)		**2,511**	**(5,043)**
Interest income		183	117
Interest expense		(3)	-
Other gains and losses – net	6	(763)	306
Profit/(loss) for the year before tax		**1,928**	**(4,620)**
Deferred income tax		(739)	559
Current income tax		(2)	(3)
Profit/(loss) for the year before		**1,187**	**(4,064)**
Basic and diluted profit/(loss) per share (in US Dollars)		0.0146	(0.050)
Weighted average number of shares outstanding		*81,017,800*	*81,017,800*

Group Statement of Comprehensive Income
(presented in US$ 000)

Year ended 31 December	2016	2015
Profit/(loss) for the year attributable to equity shareholders of the Company	**1,187**	**(4,064)**
Other comprehensive income items that may be reclassified to profit and loss:		
Currency translation differences	10,495	(15,301)
Total comprehensive (expense) for the year	**11,682**	**(19,365)**
Attributable to:		
The owners of the Parent Company	**11,682**	**(19,365)**

Group Balance Sheet
(presented in US$ 000)

At 31 December	Notes	2016	2015
ASSETS			
Non-current assets			
Intangible assets	7	3,460	2,867
Property, plant and equipment	8	55,908	48,290
Other non-current assets		4	155
Deferred tax assets		1,536	1,098
Total non-current assets		**60,908**	**52,410**
Current assets			
Cash and cash equivalents	9	19,718	6,769
Inventories	10	981	1,067
Other receivables	11	3,007	1,449
Total current assets		**23,706**	**9,285**
Total assets		**84,614**	**61,695**
EQUITY AND LIABILITIES			
Equity			
Share capital		1,485	1,485
Share premium (net of issue costs)		-	-
Other reserves		(75,622)	(86,117)
Accumulated profits		141,224	140,037
Equity attributable to the shareholders of the parent		**67,087**	**55,405**
Non-current liabilities			
Asset retirement obligation		175	146
Deferred tax liabilities		3,429	1,995
Bank loan	13	3,802	-
Total non-current liabilities		**7,406**	**2,141**
Current liabilities			
Bank loan	13	158	-
Trade and other payables	12	9,963	4,149
Total current liabilities		**10,121**	**4,149**
Total equity and liabilities		**84,614**	**61,695**

Group Cash Flow Statement
(presented in US$ 000)

Year ended 31 December	**Notes**	**2016**	**2015**
Profit/(loss) for the year before tax		**1,928**	**(4,620)**
Adjustments to profit/(loss) before tax:			
Depreciation		5,060	2,369
E & E expense		265	635
Write off of development assets		1,749	2,950
Inventory write-off		536	-
Foreign exchange differences		892	(942)
Operating cash flow prior to working capital		**10,430**	**392**
Working capital changes			
(Increase)/decrease in trade and other receivables		(1,091)	(1,144)
Increase/(decrease) in payables		3,745	1,893
(Increase)/decrease in inventory		201	22
Cash flow from operations		**13,285**	**1,163**
Income tax paid		(2)	(3)
Net cash flow generated from operating activities		**13,283**	**1,160**
Cash flows from investing activities			
Expenditure on exploration and evaluation		(499)	(554)
Purchase of property, plant and equipment		(4,534)	(8,117)
Net cash used in investing activities		**(5,033)**	**(8,671)**
Cash flows from financing activities			
Bank loans drawn		3,947	-
Equity dividends paid		-	(1,013)
Net cash outflow from financing activities		**3,947**	**(1,013)**
Effect of exchange rate changes on cash and cash equivalents		752	(474)
Net increase/(decrease) in cash and cash equivalents		**12,949**	**(8,998)**
Cash and cash equivalents at beginning of the year	9	6,769	15,767
Cash and cash equivalents at end of the year	9	**19,718**	**6,769**

Statement of Changes in Shareholders' Equity
(presented in US$ 000)

	Share Capital	Currency Translation Reserves	Share Grant Reserve	Accumulated Profit/(Loss)	Total Equity
Opening equity at 1 January 2016	**1,485**	**(91,350)**	**5,233**	**140,037**	**55,405**
Profit for the year	-	-	-	1,187	1,187
Transactions with owners	-	-	-	-	-
Currency translation differences	-	10,495	-	-	10,495
Total comprehensive income	-	10,495	-	1,187	11,682
Closing equity at 31 December 2016	**1,485**	**(80,855)**	**5,233**	**141,224**	**67,087**
Opening equity at 1 January 2015	**1,485**	**(76,049)**	**5,233**	**145,114**	**75,783**
Loss for the year	-	-	-	(4,064)	(4,064)
Transactions with owners					
Equity dividends paid	-	-	-	(1,013)	(1,013)
Total transactions with owners	-	-	-	(1,013)	(1,013)
Currency translation differences	-	(15,301)	-	-	(15,301)
Total comprehensive income	-	(15,301)	-	(4,064)	(19,365)
Closing equity at 31 December 2015	**1,485**	**(91,350)**	**5,233**	**140,037**	**55,405**

Notes to the Abbreviated Financial Statements
for the year ended 31 December 2016

1. Summary of significant accounting policies

The principal accounting policies applied in the preparation of these consolidated financial statements are set out below. These policies have been consistently applied to all the years presented, unless otherwise stated.

1.1 Basis of preparation

Both the Parent Company financial statements and the Group financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRSs"), as adopted by the European Union ("EU"), International Financial Reporting Interpretations Committee ("IFRIC") interpretations, and the Companies Act 2006 applicable to companies reporting under IFRS. The consolidated financial statements have been prepared under the historical cost convention and in accordance with applicable accounting standards.

The preparation of financial statements in conformity with IFRSs requires the use of certain critical accounting estimates. It also requires management to exercise its judgement in the process of applying the Group's accounting policies. The areas involving a higher degree of judgement or complexity, or areas where assumptions and estimates are significant to the consolidated financial statements are disclosed in note 4.

The Group's business activities, together with the factors likely to affect its future development, performance and position set out in the Strategic Report in pages 3 to 13; the financial position of the Group, its cash flows, liquidity position and borrowing facilities are described in the Financial Review on pages 9 and 10. In addition, the Group's objectives, policies and processes for measuring capital, financial risk management objectives, details of financial instruments and exposure to credit and liquidity risks are described in note 3. Having reviewed the future cash flow forecasts of the Group, the directors have concluded that the Group will continue to have access to sufficient funds in order to meet its obligations as they fall due for at least the foreseeable future and thus continue to adopt the going concern basis of accounting in preparing the annual financial statements.

Disclosure of impact of new and future accounting standards

(a) New and amended standards and interpretations:

There are no IFRSs or IFRIC interpretations that are effective for the first time for the financial year beginning on 1 January 2016 that have a material impact on the Group.

In accordance with the transitional provisions of IFRS 10, the Group reassessed the control conclusion for its investees at 1 January 2016. No modifications of previous conclusions about control regarding the Group's investees were required.

(b) Standards, amendments and interpretations to existing standards that are not yet effective and have not been early adopted by the Group. The following Adopted IFRSs have been issued but have not been applied by the Group in these financial statements. Their adoption is not expected to have a material effect on the financial statements unless otherwise indicated:

- Amendments to IFRS 2: Classification and Measurement of Share-based Payment Transactions (effective date to be confirmed)
- Amendments to IFRS 4: Applying IFRS 9 Financial Instruments with IFRS 4 Insurance Contracts (effective date to be confirmed)
- IFRS 9 Financial Instruments (effective date 1 January 2018)
- IFRS 15 Revenue from Contract with Customers (effective date 1 January 2018)
- IFRS 16 'Leases' (effective date 1 January 2019)
- Amendments to IAS 7: Disclosure Initiative (effective date 1 January 2017)
- Amendments to IAS 12: Recognition of Deferred Tax Assets for Unrealised Losses (effective date 1 January 2017)

The Group is yet to assess the full impact of these new standards and amendments but does not expect them to have a material impact on the financial statements, with the main effect being the requirement for additional disclosures.

1.2 Consolidation

The consolidated financial statements include the financial statements of the Company and its subsidiaries. Subsidiaries are entities controlled by the Group. The Group controls an entity when it is exposed to, or has rights to, variable returns from its involvement with the entity and has the ability to affect those returns through its power over the entity. In assessing control, the Group takes into consideration potential voting rights that are currently exercisable. The acquisition date is the date on which control is transferred to the acquirer. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases. Losses applicable to the non-controlling interests in a subsidiary are allocated to the non-controlling interests even if doing so causes the non-controlling interests to have a deficit balance.

Investments in subsidiaries are accounted for at cost less impairment. Cost is adjusted to reflect changes in consideration arising from contingent consideration amendments. Cost also includes direct attributable costs of investment.

Inter-company transactions, balances and unrealised gains on transactions between Group companies are eliminated; unrealised losses are also eliminated unless the cost cannot be recovered.

The Company and its subsidiaries outside the Russian Federation maintain their financial statements in accordance with IFRSs as adopted by the EU. The Russian subsidiaries of the Group maintain their statutory accounting records in accordance with the Regulations on Accounting and Reporting of the Russian Federation. The consolidated financial statements are based on these statutory accounting records, appropriately adjusted and reclassified for fair presentation in accordance with International Financial Reporting Standards as adopted by the EU.

1.3 Segment reporting

No geographic segmental information is presented as all of the companies operating activities are based in the Russian Federation.

Management has determined therefore that the operations of the Group comprise one class of business, being oil and gas exploration, development and production and the Group operates in only one geographic area - the Russian Federation.

The Group’s gas sales, representing a substantial proportion of revenues are made to a single customer. Details are provided in Note 2.1 (b).

1.4 Foreign currency translation

(a) Functional and presentation currency
Items included in the financial statements of each of the Group’s entities are measured using the currency of the primary economic environment in which the entity operates (“the functional currency”). The consolidated financial statements are presented in US Dollars, which is the Company’s functional and the Group’s presentation currency.

The functional currency of the Group’s subsidiaries that are incorporated in the Russian Federation is the Russian Rouble (“RUR”). It is the Management’s view that the RUR best reflects the financial results of its Cyprus subsidiaries because they are dependent on entities based in Russia that operate in an RUR environment in order to recover their investments. As a result, the functional currency of the subsidiaries continues to be the RUR.

(b) Transactions and balances
Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at year-end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognised in the income statement.

Foreign exchange gains and losses that relate to cash and cash equivalents, borrowings and other foreign exchange gains and losses are presented in the income statement within “Other gains and losses”.

(c) Group companies
The results and financial position of all the Group entities (none of which has the currency of a hyper-inflationary economy) that have a functional currency different from the presentation currency are translated into the presentation currency as follows:

(i) assets and liabilities for each balance sheet item presented are translated at the closing rate at the date of that balance sheet;
(ii) income and expenses for each income statement are translated at average exchange rates (unless this average is not a reasonable approximation of the cumulative effect of the rates prevailing on the transaction dates, in which case income and expenses are translated at the rate on the dates of the transactions); and
(iii) all resulting exchange differences are recognised in other comprehensive income.

The major exchange rates used for the revaluation of the closing balance sheet at 31 December 2016 were:

- GBP 1.233: US$ (2015: 1.517)
- EUR 1.052: US$ (2015: 1.091)
- US$ 1:60.657 RUR. (2015: 72.883)

1.5 Oil and gas assets

The Company and its subsidiaries apply the successful efforts method of accounting for Exploration and Evaluation ("E&E") costs, in accordance with IFRS 6 "Exploration for and Evaluation of Mineral Resources". Costs are accumulated on a field-by-field basis.

Capital expenditure is recognised as property, plant and equipment or intangible assets in the financial statements according to the nature of the expenditure and the stage of development of the associated field, i.e. exploration, development, production.

(a) Exploration and evaluation assets
Costs directly associated with an exploration well, including certain geological and geophysical costs, and exploration and property leasehold acquisition costs, are capitalised as intangible assets until the determination of reserves is evaluated. If it is determined that a commercial discovery has not been achieved, these costs are charged to expense after the conclusion of appraisal activities. Exploration costs such as geological and geophysical that are not directly related to an exploration well are expensed as incurred.

Once commercial reserves are found, exploration and evaluation assets are tested for impairment and transferred to development assets. No depreciation or amortisation is charged during the exploration and evaluation phase.

(b) Development assets
Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells into commercially proven reserves, is capitalised within property, plant and equipment. When development is completed on a specific field, it is transferred to producing assets as part of property, plant and equipment. No depreciation or amortisation is charged during the development phase.

(c) Oil and gas production assets
Production assets are accumulated generally on a field by field basis and represent the cost of developing the commercial reserves discovered and bringing them into production together with E&E expenditures incurred in finding commercial reserves and transferred from the intangible E&E assets as described above.

The cost of production assets also includes the cost of acquisitions and purchases of such assets, directly attributable overheads, finance costs capitalised and the cost of recognising provisions for future restoration and decommissioning.

Where major and identifiable parts of the production assets have different useful lives, they are accounted for as separate items of property, plant and equipment. Costs of minor repairs and maintenance are expensed as incurred.

(d) Depreciation/amortisation
Oil and gas properties are depreciated or amortised using the unit-of-production method. Unit-of-production rates are based on proved and probable reserves, which are oil, gas and other mineral reserves estimated to be recovered from existing facilities using current operating methods. Oil and gas volumes are considered produced once they have been measured through meters at custody transfer or sales transaction points at the outlet valve on the field storage tank.

(e) Impairment – exploration and evaluation assets
Exploration and evaluation assets are tested for impairment prior to reclassification to development tangible assets, or whenever facts and circumstances indicate that an impairment condition may exist. An impairment loss is recognised for the amount by which the exploration and evaluation assets' carrying amount exceeds their recoverable amount. The recoverable amount is the higher of the exploration and evaluation assets' fair value less costs to sell and their value in use. For the purposes of assessing impairment, the exploration and evaluation assets subject to testing are grouped with existing cash-generating units of production fields that are located in the same geographical region.

(f) Impairment – proved oil and gas production properties
Proven oil and gas properties are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is recognised for the amount by which the asset's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of an asset's fair value less costs to sell and value in use. The cash generating unit applied for impairment test purposes is generally the field, except that a number of field interests may be grouped together where the cash flows of each field are interdependent, for instance where surface infrastructure is used by one or more field in order to process production for sale.

(g) Decommissioning
Provision is made for the cost of decommissioning assets at the time when the obligation to decommission arises. Such provision represents the estimated discounted liability (the discount rate used currently being at 10% per annum) for costs which are expected to be incurred in removing production facilities and site restoration at the end of the producing life of each field. A corresponding item of property, plant and equipment is also created at an amount equal to the provision. This is subsequently depreciated as part of the capital costs of the production facilities. Any change in the present value of the estimated expenditure attributable to changes in the estimates of the cash flow or the current estimate of the discount rate used are reflected as an adjustment to the provision and the property, plant and equipment. The unwinding of the discount is recognised as a finance cost.

1.6 Other business and corporate assets

Property, plant and equipment not associated with exploration and production activities are carried at cost less accumulated depreciation. These assets are also evaluated for impairment when circumstances dictate.

Land is not depreciated. Depreciation of other assets is calculated on a straight line basis as follows:

Machinery and equipment	6–10 years
Office equipment in excess of US$5,000	3–4 years
Vehicles and other	2–7 years

Depreciation methods, useful lives and residual values are reviewed at each balance sheet date.

1.7 Inventories

Crude oil inventories are stated at the lower of cost of production and net realisable value. Materials and supplies inventories are recorded at average cost and are carried at amounts which do not exceed the expected recoverable amount from use in the normal course of business. Cost comprises direct materials and, where applicable, direct labour plus attributable overheads based on a normal level of activity and other costs associated in bringing inventories to their present location and condition.

1.9 Trade and other receivables

Trade and other receivables are recorded initially at fair value and subsequently measured at amortised cost using the effective interest method, less provision for impairment. A provision for impairment of trade receivables is established when there is objective evidence that the Group will not be able to collect all amounts due according to the original terms of the receivables. The amount of the provision is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the original effective interest rate.

1.10 Trade payables

Trade payables are recognised initially at fair value and subsequently measured at amortised cost using the effective interest method.

2. Financial risk management

2.1 Financial risk factors

The Group's activities expose it to a variety of financial risks: market risk (including foreign exchange risk, price risk, and cash flow interest rate risk), credit risk, and liquidity risk. The Group's overall risk management programme focuses on the unpredictability of financial markets and seeks to minimise potential adverse effects on the Group's financial performance.

(a) Market risk

(i) Foreign exchange risk
The Group is exposed to foreign exchange risk arising from currency exposures, primarily with respect to the RUR. Foreign exchange risk arises from future commercial transactions, recognised assets and liabilities.

The following table shows the currency structure of financial assets and liabilities:

At 31 December 2016	**Rubles**	**US Dollars**	**Euros**	**Sterling**	**Total**
	US$ 000	**US$ 000**	**US$ 000**	**US$ 000**	**US$ 000**
Financial assets					
Cash and cash equivalents	6,747	12,810	13	148	19,718
Total financial assets	**6,747**	**12,810**	**13**	**148**	**19,718**
Financial liabilities	11,389	-	-	-	11,389

At 31 December 2015	**Rubles**	**US Dollars**	**Euros**	**Sterling**	**Total**
	US$ 000	**US$ 000**	**US$ 000**	**US$ 000**	**US$ 000**
Financial assets					
Cash and cash equivalents	1,089	5,622	14	44	6,769
Total financial assets	**1,089**	**5,622**	**14**	**44**	**6,769**
Financial liabilities	3,217	-	-	-	3,217

(ii) Price risk
The Group is not exposed to price risk as it does not hold financial instruments of which the fair values or future cash flows will be affected by changes in market prices. The Group is not directly exposed to the levels of international marker prices of crude oil or oil products, although these clearly influence the prices at which it sells its oil and condensate. Mineral Extraction Taxes ("MET") are calculated by reference to Urals oil prices and are therefore directly influenced by this. Taking into account the marginal rates of export taxes and MET, management estimates that if international oil prices had been US$5 per barrel higher or lower and all other variables been unchanged, the Group's profit before tax would have been US$2.7 million higher or lower (2015: $1.4 million).

(iii) Cash flow and fair value interest rate risk

As the Group currently has no significant interest-bearing assets and liabilities, the Group's income and operating cash flows are substantially independent of changes in market interest rates.

(b) Credit risk
The Group's maximum credit risk exposure is the fair value of each class of assets, presented in note 3.1(a)(i) of US$19,718,000 and US$6,769,000 at 31 December 2016 and 2015 respectively.
The Group's principal financial asset is cash and credit risk arises from cash and cash equivalents and deposits with banks and financial institutions. It is the Group's policy to monitor the financial standing of these assets on an ongoing basis. Bank balances are held with reputable and established financial institutions.

The Group's oil and condensate sales are normally undertaken on a prepaid basis and accordingly the Group has no trade receivables and consequently no credit risk associated with the related trade receivables. Gas sales accounting for 35.6% of Group revenues in 2016 (2015: 38.4%) were made to OOO Trans Nafta. As at 31 December 2016 there were trade receivables of US$2.0million (31 December 2015: US$1.0 million) relating to gas sales. As at 31 December 2016 there was no provision for bad debts (2015: nil).

Rating of financial institution (Fitch)		31 December 2016 US$000	31 December 2015 US$000
Barclays Bank	A	3,627	4,794
ZAO Raiffeisenbank	BBB-	15,840	1,579
Unicreditbank	BBB-	214	202
Other		37	194
Total bank balance		**19,718**	**6,769**

(c) Liquidity risk
Cash flow forecasting is performed by Group finance. Group finance monitors rolling forecasts of the Group's liquidity requirements to ensure it has sufficient cash to meet operational needs. The Group believes it has sufficient liquidity headroom to fund its currently planned exploration and development activities.

The Group expects to fund its capital investments, as well as its administrative and operating expenses, through 2016 using a combination of cash generated from its oil and gas production activities, existing working capital and, when appropriate, medium-term bank borrowings. If the Group is unsuccessful in generating enough liquidity to fund its expenditures, the Group's ability to execute its long-term growth strategy could be significantly affected. The Group may need to raise additional equity or debt finance as appropriate to fund investments beyond its current commitments.

(d) Capital risk management
The Group manages capital to ensure that it is able to continue as a going concern whilst maximising the return to shareholders. The Group is not subject to any externally imposed capital requirements. The Board regularly monitors the future capital requirements of the Group, particularly in respect of its ongoing development programme. Management expects that the cash generated by the operating fields will be sufficient to sustain the Group's operations and future capital investment for the foreseeable future. During December 2016, one of the Group's operating subsidiaries entered into a loan agreement of RUR 240 million to fund its LPG project (see note 20). This loan, which has a three year amortising term, benefits from an interest rate subsidy provided by the regional Government. Further short-term debt facilities may be arranged to provide financial headroom for future development activities.

3. Critical accounting estimates and judgements

The Group makes estimates and assumptions concerning the future. The resulting accounting estimates will, by definition, seldom equal the related actual results. The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below.

a) Carrying value of fixed assets, intangible assets and impairment
Fixed assets and intangible assets are assessed for impairment when events and circumstances indicate that an impairment condition may exist. The carrying value of fixed assets and intangible assets are evaluated by reference to their value in use and primarily looks to the present value of management's best estimate of the cash flows expected to be generated from the asset. In identifying cash flows management firstly determine the cash generating unit or group of assets that give rise to the cash flows. The cash generating unit ("CGU") is the lowest level of asset at which independent cash flows can be generated. For this purpose the directors consider the Group to have two CGUs: the VM and Dobrinskoye fields with the Dobrinskoye gas processing plant are treated as a single CGU, and the Uzen oil field is a separate CGU.

The estimation of forecast cash flows involves the application of a number of significant judgements and estimates to a number of variables including production volumes, commodity prices, operating costs, capital investment, hydrocarbon reserves estimates and discount rates. Key assumptions and estimates in the impairment models relate to:

- International oil prices: flat real prices reflecting the actual levels pertaining in the period between 31 December 2016 and 1 March 20–7 - Urals oil price of US$53 per barrel. No forward price escalation is assumed.

- Selling prices for oil, condensate and LPG that reflect international oil prices, less export taxes at the current applicable official rates and a price differential of $5 per barrel to reflect transportation costs
- Gas sales price of RUR 3,898 per mcm excluding VAT.
- Production profiles based on remaining reserves in the Proved category and approved field development plans. In the Group's base case, however, LPG revenues are not assumed although, as indicated below, the capital expenditures for this project are included.
- Capital expenditures required to deliver the above production profiles and to maintain the production assets throughout the field life. Total development capital expenditure assumed is US$18 million with future maintenance capital expenditure of up to US$1 million per annum. This includes US$5 million for the LPG extraction project.
- Cost assumptions are based on current experience and expectations and are broadly in line with unit costs experienced in the year ended 31 December 2016. The projections assume that the current gas sweetening process is maintained. If Redox-based sweetening is successfully implemented, however, the Group expects to realise significant cost savings.
- Export and mineral extraction taxes reflect rates set by current legislation.
- The model reflects real terms cash flows with no inflationary escalation of revenues or costs.
- A real discount rate of 12% per annum is utilised in the models.
- An exchange rate of RUR60 to US$1.00 is assumed.

In addition to the base case a number of sensitivity cases have been carried out: varying oil and gas prices by 10%, varying operating expenditure by 10%, varying capital expenditure by 20% and using a 15% real discount rate.

As at 31 December 2016, the Group's impairment testing of the property, plant and equipment related to each CGU indicated that no impairment was required. In addition, the sensitivities described above yielded net present values in excess of carrying value for each CGU. Furthermore, two initiatives planned by the Group in 2017: a switch to Redox-based gas sweetening and construction of an LPG extraction module, are each expected to result in material increases in the value in use of the relevant CGU.

(b) Estimation of oil and gas reserves

Estimates of oil and gas reserves are inherently subjective and subject to periodic revision. In addition, the results of drilling and other exploration or development activity will often provide additional information regarding the Group's reserve base that may result in increases or decreases to reserve volumes. Such revisions to reserves can be significant and are not predictable with any degree of certainty. Management considers the estimation of reserves to represent a significant judgement in the context of the financial statements as reserve volumes are used as the basis for assessing the useful life of oil and gas assets, applying depreciation to oil and gas assets and in assessing the carrying value of oil and gas assets. Decreases in reserve estimates can lead to significant impairment of oil and gas assets where revisions (positive or negative) can have a significant effect on depreciation rates from period to period. Management have considered the sensitivity of this key assumption and in order for an impairment issue to present itself to the Group, reserve estimates would need to reduce by more than 12% below the level of recently revised proved reserves as at 31 December 2016.

An independent assessment of the reserves and net present value of future net revenues ("NPV") attributable to the Group's fields, Dobrinskoye, Vostochny Makarovskoye, Sobolevskoye and Uzenskoye, as at 31 December 2016, was prepared in accordance with reserve definitions set by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers ("SPE"). The latest assessment resulted in revisions that increased the level of proven and probable reserves as at 31 December 2016 by 2.4% and decreased the level of proved reserves by 10.8%.

4. Revenue

Year ended 31 December	2016	2015
	US$ 000	**US$ 000**
Oil	7,523	4,081
Condensate	17,857	6,875
Gas	14,032	6,871
Total revenues	**39,412**	**17,827**

All revenue is generated from the sale of oil and gas in the ordinary course of the Group's activities.

5. Cost of sales and administrative expenses

Cost of sales and administrative expenses are as follows:

Year ended 31 December	2016	2015
	US$ 000	**US$ 000**
Production expenses	10,968	7,367
Mineral extraction taxes	10,255	5,877
Depletion, depreciation and amortisation	5,037	2,345
Cost of Sales	**26,260**	**15,589**

Total expenses are analysed as follows:

Year ended 31 December		2016	2015
		US$ 000	**US$ 000**
Export sales related expenses	(a)	4,052	319
Field operating expenses		9,367	6,016
Mineral extraction tax		10,255	5,876
Depreciation & amortisation		5,059	2,369
Exploration & evaluation		265	635
Write off of development assets	(b)	1,798	2,950
Inventory write off	(c)	529	-
Salaries & staff benefits		3,177	2,471
Directors' emoluments and other benefits		645	765
Audit fees		314	203
Taxes other than payroll and mineral extraction		38	44
Legal & consulting		291	480
Other		1,110	742
Total		**36,900**	**22,870**

(a) *Selling expense:* comprise export taxes and costs associated with delivering gas condensate sales to export customers.

(b) *Write-off of development assets:* In the year ended 31 December 2016, the principal source of the write off of development assets was the US$1.650 million compensation payable to Schlumberger for logging tools stuck in the Uzen #4 well sidetrack. The write off incurred in the year ended 31 December 2015 was related mainly to the Sobolevskoye field.

(c) *Inventory write-off:* In the year ended 31 December 2016, certain obsolete and unused items of production equipment were transferred from producing assets to inventory and then written off (2015: nil).

6. Other gains and losses

Year ended 31 December	2016	2015
	US$ 000	**US$ 000**
Foreign exchange (loss)/gain	(892)	942
Recovery of/(loss from) unauthorised bank transfers	37	(727)
Other gains	92	91
Total other (losses)/gains	**(763)**	**306**

7. Intangible assets

Intangible assets represent exploration and evaluation assets such as licences, studies and exploratory drilling, which are stated at historical cost, less any impairment charges or write-offs.

	Work in progress: exploration and evaluation	Exploration and evaluation	Total
At 1 January 2016	117	2,750	2,867
Additions	-	254	254
Write offs and impairments	-	(240)	(240)
At 31 December 2016	**117**	**2,764**	**2,881**
Exchange adjustments	23	556	579
At 31 December 2016	**140**	**3,320**	**3,460**

	Work in progress: exploration and evaluation	Exploration and evaluation	Total
At 1 January 2015	151	3,595	3,746
Additions	-	606	606
Write offs and impairments	-	(635)	(635)
At 31 December 2015	**151**	**3,566**	**3,717**
Exchange adjustments	(34)	(816)	(850)
At 31 December 2015	**117**	**2,750**	**2,867**

8. Property, plant and equipment – Group

Movements in property, plant and equipment, for the year ended 31 December 2016 are as follows:

Cost	**Development assets US$ 000**	**Land & buildings US$ 000**	**Producing assets US$ 000**	**Other US$ 000**	**Total US$ 000**
At 1 January 2016	1,137	650	55,879	498	58,164
Additions	2,341	-	1,564	-	3,905
Write-offs and impairments	(57)	-	(917)	-	(974)
Transfers	(294)	-	294	-	-
Exchange adjustments	432	130	11,359	100	12,021
At 31 December 2016	3,559	780	68,179	598	73,116
Accumulated depreciation					
At 1 January 2016	-	-	(9,399)	(475)	(9,874)
Adjustment for assets written off	-	-	195	15	210
Depreciation	-	-	(5,028)	(32)	(5,060)
Exchange adjustments	-	-	(2,387)	(97)	(2,484)
At 31 December 2016	-	-	(16,619)	(589)	(17,208)
Net book value 31 Dec 2016	**3,559**	**780**	**51,560**	**9**	**55,908**

Movements in property, plant and equipment, for the year ended 31 December 2015 are as follows:

Cost	Development assets US$ 000	Land & buildings US$ 000	Producing assets US$ 000	Other US$ 000	Total US$ 000
At 1 January 2015	8,523	842	57,944	701	68,010
Additions	378	-	9,422	-	9,800
Write-offs and impairments	(673)	-	(2,338)	(51)	(3,062)
Transfers	(6,181)	-	6,181	-	-
Exchange adjustment	(910)	(192)	(15,330)	(152)	(16,584)
At 31 December 2015	1,137	650	55,879	498	58,164
Accumulated depreciation					
At 1 January 2015	-	-	(9,589)	(599)	(10,188)
Adjustment for assets written off	-	-	10	51	61
Depreciation	-	-	(2,384)	(66)	(2,450)
Exchange adjustment	-	-	2,564	139	2,703
At 31 December 2015	-	-	(9,399)	(475)	(9,874)
Net book value 31 Dec 2015	**1,137**	**650**	**46,480**	**23**	**48,290**

9. Cash and cash equivalents – Group and Company

An analysis of Group cash and cash equivalents by bank and currency is presented in the table below:

At 31 December		**2016**	**2015**
Bank	**Currency**	**US$ 000**	**US$ 000**
United Kingdom			
Barclays Bank PLC	USD	3,479	4,750
Barclays Bank PLC	GBP	148	44
Russian Federation			
Unicreditbank	RUR	82	70
Unicreditbank	USD	131	195
ZAO Raiffeisenbank	RUR	6,628	825
ZAO Raiffeisenbank	USD	9,200	740
ZAO Raiffeisenbank	EUR	13	132
Other banks and cash on hand	RUR	37	13
Total cash and cash equivalents		**19,718**	**6,769**

10. Inventories – Group

At 31 December	**2016 US$ 000**	**2015 US$ 000**
Production consumables and spare parts	796	704
Crude oil inventory	185	363
Total inventories	**981**	**1,067**

11. Other receivables – Group

At 31 December	Group 2016 US$ 000	2015 US$ 000
VAT receivable	154	80
Prepayments	725	298
Trade receivables	2,067	987
Other accounts receivable	61	84
Total other receivables	**3,007**	**1,449**

Prepayments are to contractors and relate to initial advances made in respect of drilling, construction and other projects. Trade receivables relate to sales of gas and condensate. The receivables were settled on schedule subsequent to the balance sheet date.

12. Trade and other payables

At 31 December	Group 2016 US$ 000	2015 US$ 000
Trade payables	4,861	2,467
Taxes other than profit tax	2,266	750
Customer advances	2,836	932
Total	**9,963**	**4,149**

The maturity of the Group's and the Company's financial liabilities are all between zero to three months. Customer advances are prepayments for oil and condensate sales, normally one month in advance of delivery.

13. Bank loan

At 31 December	2016 US$ 000	2015 US$ 000
Non-current liabilities		
Secured bank-loan	3,802	-
Current liabilities		
Current portion of secured bank loan	158	-
Total Bank Loan	**3,960**	**-**

In December 2016, the Group received bank loan in total amount of RUR 240 million (US$3.96 million), which will be utilised to fund purchases of equipment for the LPG project and should be fully repaid by 2019 (repayments in 2017: US$0.16 million; 2018: US$1.9 million; 2019: US$1.9 million). Interest is charged at a fixed rate of 11.45% per annum. The Bank loan as at 31 December 2016 has been secured by charges over the shares of the Group's Russian operating subsidiaries.