INTERIM RESULTS

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Volga Gas PLC
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Volga Gas plc
('Volga Gas' or 'the Company' or 'the Group')

INTERIM RESULTS

Volga Gas, the oil and gas exploration and production group operating in the Volga region of Russia, announces its interim results for the six months ended 30 June 2019.

OIL, GAS AND CONDENSATE PRODUCTION

- Group production averaged 5,634 boepd in H1 2019 (H1 2018: 4,727), a 19% increase.
- Gas and condensate production were 20.0 mmcf/d, and 1,525 bpd, respectively (H1 2018: 16.8 mmcf/d, a 19% increase and 1,114 bpd, a 37% increase), as the capacity increases achieved at the gas plant during 2H 2018 were sustained.
- LPG production added a further 352 boepd (H1 2018 82 boepd, as LPG commenced only in May 2018).
- Oil production averaged 419 bopd (H1 2018: 729 bopd), a 43% decrease, reflecting natural declines at the mature Uzen oil field.

FINANCIAL RESULTS

- Revenues increased 22% to US$26.3million (H1 2018: US$21.5 million). With resumed exports of oil and condensate in H1 2019 revenues net of selling expenses increased 11% to US$23.4 million (H1 2018: US$21.1 million).
- EBITDA increased 38% to US$9.3 million (H1 2018: US$6.7 million).
- In addition to a US$1.9 million write off of development costs (H1 2018: US$1.6 million), the Group is recognising a provisional US$3.2 million asset impairment charge (H1 2018: nil) relating to the anticipated reserve revision. The final impairment will be calculated at the 2019 year end based on independent reserve estimates and evaluations.
- With increased DD&A charges resulting from the anticipated reserve revision and the above mentioned charges, the Group is reporting an operating loss of US$2.6 million (H1 2018: operating profit of US$1.0 million).
- Loss before tax of US$3.0 million (H1 2018: profit before tax of US$4.2 million) and net loss after tax of US$2.5 million (H1 2018: net income of US$3.3 million.
- Cash flow from operations was US$ 9.7 million (H1 2018: US$10.3 million) before working capital outflow of US$0.7 million (H1 2018: inflow of US$49,000) and payment of US$1.6 million in income taxes (H1 2018: US$21,000).
- Cash used in capital expenditure was US$3.3 million (H1 2018: US$2.0 million) comprised drilling costs on sidetrack wells and gas plant maintenance and improvements and included US$64,000 on exploration and evaluation (H12018: nil)..
- Cash balance decreased to US$12.4 million as at 30 June 2019 (31 December 2018: US$15.2 million), after paying dividends of US$5.2 million (H1 2018: nil), US$0.4 million of purchase of own shares (H1 2018: nil), US$1.8 million on loan repayments (H1 2018: US$1.0 million) and US$ 3.3 million cash on capital expenditure items (H1 2018: US$2.0 million).
- There were no outstanding borrowings as at 30 June 2019 (31 December 2018: US$1.7 million), following repayments of the final balances in February 2019.

DEVELOPMENT ACTIVITY

- A sidetrack well to VM#2 was drilled late in 2018 with the aim of restoring production. Following an unsuccessful test of this well and ingress of water in the VM#3 well, management expects a downward revision in reserves in the VM field in the region of 4.1 mmboe to the field reserves as at 1 January 2019.
- Completion of an ongoing reservoir study on the VM field will provide a new independent estimate as well as a plan for the future development of additional fault blocks that are currently not accessed by existing wells.
- The Uzen #4 sidetrack well, which was drilled into an undeveloped pool in the Albian reservoir layer of the Uzen oil field encountered pay that was largely gas rather than oil saturated. This well is thus commercially unsuccessful and the expected reserves of 0.5 million barrels associated with this pool will need to be incorporated.
- More positively, the Group has had a successful start with the slim hole drilling technique which has enabled a total of four of the oil production wells to be drilled to date. Currently a fifth well is in progress, to be followed by a sixth. Management estimates the average cost of the slim hole wells to be US$200,000.
- One of these slim hole wells has discovered oil in a previously unevaluated geological layer, the Upper Aptian, at a depth of approximately 900 metres. Preliminary management estimates suggest potential additional reserves of up to 3.7 mmbbls of recoverable oil reserves in this layer in the Uzen field. An appraisal well will be the next step to assess this new discovery.
- Slim hole drilling will also be applied shortly on two undrilled exploration prospects which management considers to have potential for the discovery of new oil reserves. It is also planned to be used as a low cost method of developing further

production on the VM field.

- The gas processing plant, meanwhile, has operated efficiently during period and, with minor upgrades, resulting in reduced operating costs. Effective capacity of the plant has increased to over 25 mmcf/day excluding maintenance downtime. Modifications to the LPG unit approved by the Board at the start of 2019 are being implemented.

DIVIDEND

- In light of the current outlook and the need to target its financial resources towards stabilizing and rebuilding future production levels, the Board has decided to suspend cash dividends.

POST PERIOD UPDATE

- During July and August 2019, Group production averaged 4,633 boepd. Management guidance remains at 2,830 boepd for the remainder of 2019.
- At 31 August 2019, the Group net cash balance was at US$11.6 million, having paid US$2.6 million on capital expenditure and generated positive operating cash flow during July and August 2019. The Group remains debt free.

OUTLOOK

- Full year production guidance of 4,400 boe
- Operational focus on stabilising gas and condensate production in the VM field
- Programme of low cost, slim hole drilling technique commenced at VM to be extended to conduct exploration on two of the undrilled prospects within its Karpensky Licence.
- Capital expenditure plans for H2 2019 total US$4.8 million, including the US$2.5 million incurred during July and August 2019.

Andrey Zozulya, Chief Executive Officer of Volga Gas, said:
"Notwithstanding the recent, solid underlying production performance of the Group, adverse drilling and other operational issues have impacted overall financial results and future management production guidance.

Management is determined to mitigate the expected future lower production guidance. This includes the application of low-cost, slim hole drilling techniques, which have already been successfully deployed on the Uzen field, and apply to up to six attractive exploration targets. The plan is to initially drill two slim hole exploration wells in the Karpenskiy exploration area with four further slim hole exploration wells to potentially follow. Slim hole drilling may also be utilised in the future drilling in the VM field as well as on the Muradymosky licence in Bashkiriya.

The unexpected discovery of new reserves in the Upper Aptian layer in the Uzen field is potentially material to management's rebuilding strategy and the Board looks forward to drilling an appraisal well in due course, consequently the Board continues to look to the future with confidence."

For further information, please contact:

Volga Gas plc	
Andrey Zozulya, Chief Executive Officer	+7 903 385 9889
Vadim Son, Chief Financial Officer	+7 905 381 4377
Tony Alves, Investor Relations consultant	+44 7824 884 342
FTI Consulting	+44 (0)20 3727 1000
Alex Beagley, Fern Duncan	
S.P. Angel Corporate Finance LLP	+44 (0)20 3470 0470
Richard Redmayne, Richard Morrison, Richard Hail	

Editors' notes:

Volga Gas is an independent oil and gas exploration and production company operating in the Volga region of 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.

This announcement contains inside information as defined in EU Regulation No. 596/2014 and is in accordance with the Company's obligations under Article 17 of that Regulation.

Glossary

Bopd	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
Bpd	Barrels per day
mcf	thousands of standard cubic feet
mcm	thousands of standard cubic metres
mcm/d	thousands of standard cubic metres per day
m^3	standard cubic metre
mmcf/d	millions of standard cubic feet per day
mmcm/d	millions of standard cubic metres per day
RUR	Russian Rouble

Interim Management Report

Volga Gas and its subsidiaries (together, the "Group") are involved in the production of and exploration for oil and gas in five licence areas in the Volga Region of Russia.

During H1 2019 Volga Gas achieved a higher average production rate of 5,634 boepd compared to H1 2018, production of 4,727 boepd, facilitated by high levels of capacity availability at the Dobrinskoye gas processing plant and the addition of LPG volumes. However, as announced on 17 July, increased presence of formation water was measured in the wells on the VM field. This has indicated that reserve estimates are likely to be revised and, in order to manage production for a longer period management has opted to reduce the output from the VM wells.

Meanwhile, with the assistance of independent consultants from Schlumberger, an ongoing reservoir study is to be completed in the coming months. This will provide an updated assessment of remaining recoverable reserves in the field as well as a plan to maximise extraction of gas and condensate over the field's economic life. This is likely to include additional production wells.

During H1 2019, international oil prices were slightly lower at US$66 per barrel compared to US$70 per barrel during H1 2018. As a consequence, net realisation for Volga Gas' oil and condensate sales decreased by 6% to US$41.33 per barrel (H1 2018: US$43.80 per barrel). As independent refiners in Russia are finding their economics impacted by changes to the oil taxation regime, it has been necessary to resume exports, particularly of condensate. Consequently, exports of oil and condensate in H1 2019 comprised 34% of the total sales volume (H1 2018: 0% of the total sales of liquids).

The Russian Ruble exchange rate in H1 2019 was weaker than H1 2018. Consequently the average gas sales price in H1 2019 was US$1.95 per mcf (H1 2018: US$2.07/mcf).

Net revenues for H1 2019 were 11% higher than those reported in H1 2018, after taking into account transport costs and taxes paid on exports. In addition EBITDA for H1 2019 was 39% higher than for H1 2018, with lower production costs offset by increased rates of Mineral Extraction Taxes. However, higher rates of depletion, depreciation and amortisation based on management's provisional estimate of the anticipated revision to reserves to be recognised at the 2019 year end, together with related write offs of development expenditure and impairments led to the Group to report an operating loss for H1 2019 of US$2.6 million (H1 2018: operating profit of US$1.0 million).

Production Operations

Gas and condensate production - Dobrinskoye and VM fields

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 H1 2019, gas and condensate production was derived primarily from the three most productive wells on the VM field and the Dobrinskoye #26 well on which a sidetrack was successfully drilled during December 2018. As evidenced by the production numbers achieved in June 2019, the effective capacity of the wells is in the region of 22 mmcf/d of gas, plus associated condensate. The actual production in H1 2019 reflected the impact of some scheduled plant downtime required for normal maintenance operations and maintenance operations undertaken on the Gazprom pipeline into which the sales gas is delivered.

In contrast, during H1 2018 the gas plant capacity was constrained as work was done to improve the efficiency of the Redox process. In addition, during H1 2018, management opted to manage production from the VM field conservatively while monitoring the water incursion.

Consequently, average production of gas, condensate and LPG for H1 2019 were 20.0 mmcf/d, 1,525 bpd and 352 boepd respectively (H1 2018: 16.8 mmcf/d, 1,114 bpd and 82 boepd respectively).

The netback gas sales price in Ruble terms during H1 2019 was RUR 4,163 per thousand cubic metres excluding VAT (H1 2018: RUR 4,026). The Ruble has been relatively stable during H1 2019. Nevertheless, the average selling price for gas for H1 2019 equated to US$1.95 per mcf (H1 2018: US$2.07/mcf) was lower. The Ruble weakened dramatically in March 2018, resulting in a higher average US$ equivalent in H1 2018. After selling expenses, the net realisation for gas was US$1.84 per mcf (H1 2018: US$1.93 per mcf).

In contrast to H1 2018, when there were no exports, during H1 2019 approximately 63% of condensate was sold to export customers. Changes to the structure of export taxes of oil and refined products which came into effect on 1 January 2019 impacted the independent refining industry in Russia and reduced the domestic demand for refinery feedstock.

Unit production costs on the gas-condensate fields and gas plant were approximately US$3.63 per boe (H1 2018: US$5.14). This reflected benefit of the reduction in the costs of consumables with the switch to Redox based sweetening which substantially reduced variable costs and the benefit of the fixed costs being spread over a larger amount of production. Following the reduction of production implemented from July onwards, this is not anticipated to be sustained in H2 2019.

Oil production - Uzenskoye field

During H1 2019, oil production averaged 419 bopd (H1 2018: 729 bopd). The interruption to oil deliveries from the Uzen field during the spring thaw in 2019 was greater than in H1 2018. In addition, overall production capacity is lower as a result of natural declines in this mature field.

Unit production costs on the Uzen oil field were approximately US$7.46 per barrel (H1 2018: US$6.20) as production volumes declined.

Development

VM and Dobrinskoye Fields

During late 2018 and early 2019 sidetracks were drilled from the Dobrinskoye #26 and the VM#2 wells, neither of which were at the time in production. The Dobrinskoye #26 sidetrack was successfully completed and commenced production in February 2019.

The sidetrack, on the VM#2 well, was completed on 17 February 2019. This well was drilled on a deviated path and a total reservoir intersection of 71 metres of pay was logged in the well in a zone with average reservoir thickness of 13 metres. During testing however, there was water observed in the well which management initially believed to be entering through a geological fault from beneath the reservoir. A workover was carried out to place a cement plug at the bottom of the hole to isolate the water. However, this intervention failed to stem the flow of water which now seems to originate from within the reservoir.

Separately, management decided to run a production log in the nearby VM#3 using a Schlumberger FSI multiphase production logging tool. The results of the logging on several runs showed the gas:water contact was higher than expected. This high level of gas:water contact seems to be the likely explanation of the result of the testing on the VM#2 sidetrack.

Management continues to evaluate the results. However, the initial conclusions are:

- VM#2 and VM#3 appear to produce from the same reservoir block, and that the reserves in this block are now largely depleted
- VM#1 and VM#4 continue to produce at good rates suggesting that the gas:water contact in this fault block is lower than in the fault block in which the VM#3 well is located and, encouragingly, this is where the majority of the VM field remaining reserves are located
- Production rates on the two producing VM wells have been reduced in order to minimise the risk of additional water breakthrough.

As part of an ongoing reservoir study, reinterpretation of 3-D seismic has indicated the potential presence of undeveloped reserves on the eastern flank of the existing developed areas where the structural high appears to be located, as well as on a separate fault block to the north of the existing reservoir. Pending finalisation of the technical studies, management proposes to drill further production wells on the VM field to access these potential reserves. In order to minimise the cost of drilling and the financial risk, it is planned to drill these wells using slim hole drilling.

The remaining reserves in the VM field are to be reviewed and adjusted in accordance with the latest information. Whilst the independent reserve estimation has yet to be concluded, preliminary analysis indicates it would be in the order of approximately 4.1 mmboe or 21% of the total Group's proved reserves as at 1 January 2019.

Gas plant

The Redox based gas sweetening process continues to operate efficiently. Further minor upgrades to the operation have been undertaken that should enable more efficient recycling of sweetening reagents and reduce operating costs. Management estimates that the effective capacity of the plant has increased to over 25 mmcf/day excluding maintenance downtime.

LPG plant

The LPG plant commenced test production in May 2018 and has been in operation since then. LPGs, primarily comprising propane and butane, were previously either included in the sales gas stream or flared. The LPG project provides an additional product stream which during H1 2019 provided 348 boepd of sales.

Management is targeting further improvements in the efficiency of LPG extraction to increase the yields from the gas stream. To this end, a new heat exchanger was installed in June 2019 and a turbo expander has been ordered. This will enable a greater proportion of propane to be captured in the LPG. The turbo expander is expected to be installed later in 2019. The total amount of investment in the upgrades is approximately US$2.0 million.

Uzen oil field

Production from the mature wells in the Aptian reservoir of the Uzen field has continued its natural decline. Since 2017 management's attention has been on the development of the previously undeveloped shallower Albian reservoir. Activity during 1H 2019 included the sidetrack to the Uzen#4 well which was drilled into an undeveloped pool in the Albian reservoir. Whilst the well was successfully drilled, after a series of production tests, it was concluded that the pool into which the well was drilled was charged primarily with gas rather than oil. This small gas accumulation is not of significant commercial potential - although the gas can be utilised for in field fuel requirements. Consequently, the Group has decided to write off the reserves associated with this accumulation, approximately 500,000 barrels of recoverable oil, and has written off the cost of this well.

Under a more recent initiative, the Group has commenced a programme of drilling four slim hole wells in the Albian reservoir. This uses a light truck mounted rig than can drill wells of up to 1,000 metres in depth. These wells are a fraction of the cost of a conventional well. Management expects this to be the most economic method of developing this reservoir.

To date, four of the six wells have been drilled at an average cost of approximately US$200,000 each and are expected to produce on average 35 bpd of oil from each well.

Discovery of additional resource at Uzen

During the drilling of one of the new slim production wells on the Uzen field, a previously unevaluated Upper Aptian layer was found to be oil bearing and potentially productive. This layer at a depth of approximately 900 metres has a measured thickness of 7.6 metres at this location.

By comparison, the lower Aptian layer, from which the great majority of production from the Uzen field has been derived to date, is at a depth of approximately 1000 metres with thickness of 8.3 metres, while the Albian layer currently being developed is at depth around 800 metres with thickness of 6.9 metres.

Based on available seismic and well logging data, management has made a preliminary estimate of recoverable reserves from upper Aptian layer of 3.75 mmbbl of oil.

As a newly identified resource, Volga Gas is required to prepare a drilling project, drill at least one appraisal well, calculate the reserves and submit development plans for approval by the State Reserves Committee. The normal timeline for this approval process is approximately one year.

Exploration strategy

The Group also plans to utilise slim hole drilling to conduct exploration of a number of oil prospects within its Karpenskiy licence. Initially two of the prospects identified in the recently completed geological study of the licence area are planned to be drilled before the year end.

Management believes that slim hole drilling could be employed also at the Muradymosky licence in Bashkiriya.

Given the multiplicity of low-cost slim hole drilling opportunities, management has decided that it would be advantageous from both a cost and operational perspective for the Group to acquire its own drilling rig. This is being undertaken at a cost of approximately US$700,000. The order has been placed to purchase a Christensen CT20 rig, which has a higher power and reach than the one provided by the contractors drilling the current six well campaign on Uzen. The rig is in transit and is expected to be delivered within the coming months.

Financial Review

Results of Operations

For the six months ended 30 June 2019, Group revenues were US$26.3 million (H1 2018: US$21.5 million) driven by higher volumes and gross pricing of condensate exports, partly offset by lower international prices for oil and condensate. Production costs were approximately 10% lower than in H1 2018, mainly as a result of savings on gas processing chemicals but Mineral Extraction Tax rates increased with rising volumes and increases in the formula rates. Depletion and Depreciation increased as a result of higher production volumes, while the reduction in reserves also led to an increase in the unit rate of DD&A applied to the higher production volumes. Nevertheless, gross profits for H1 2019 increased to US$8.2 million (H1 2018: US$5.5 million), helped, as mentioned above, by gross pricing of condensate exports.

As exports of oil and condensate increased substantially during H1 2019, the amounts of export tax and transport expenses, which were minimal in H1 2018 also increased substantially. As a consequence selling expenses increased to US$3.0 million in H1 2019 (H1 2018: US$0.5 million). During H1 2018, selling expenses effectively only comprised transportation costs and fees associated with gas sales.

Write off of development assets and impairment charges

Following the adverse operational results on the VM field and with the Uzen #4 well sidetrack, management has written off the costs associated with the sidetrack wells on both the VM#2 and Uzen #4 wells. These amounted to US$1.9 million in H1 2019 (H1 2018: US$1.6 million).

In addition, with anticipated reserve revisions, management has provisionally calculated an impairment to the holding value of the PP&E associated with these assets. Consequently impairment charges totalling US$3.2 million are provided in H1 2019 (H1 2018: nil). At the year end 2019, following the conclusion of an independent evaluation of reserves, a final decision on asset impairment will be made. The final level of impairment will depend on the outcome of the independent reserve assessment, the production performance of the fields for the remainder of the year, the extent to which additional development drilling and other capital expenditure may be required and the prevailing oil price and other economic factors.

Income

After administrative expenses of US$2.7 million (H1 2018: US$2.4 million), the Group recorded an operating loss of US$2.6 million (H1 2018: profit of US$1.0 million).

Net interest income was US$147,000 (H1 2018: US$187,000). After recording other net expenses of US$0.5 million (H1 2018: other net gains of US$3.0 million), the Group reported loss before tax of US$3.0 million (H1 2018: profit before tax of US$4.2 million). Included in other net gains in H1 2018 was a US$3.3 million court award granted in the Group's favour against a drilling contractor.

For the period, there was a current tax provision of US$1.4 million (H1 2018: US$0.6 million) offset by a deferred tax credit of US$1.9 million (H1 2018: deferred tax charge of US$0.2 million), leading to a net loss after tax of $2.5 million for H1 2019 (H1 2018: net profit after tax of $3.3 million).

EBITDA, calculated as operating profit before exploration expenses, depletion and depreciation, asset write offs and impairment charges was US$9.3 million (H1 2018: US$6.7 million) as below:

	2019	**2018**
Operating (loss)/profit	(2,633)	1,011
Write off of development assets and impairments	5,097	1,596
Depletion Depreciation and Amortization	6,858	4,119
EBITDA	**9,322**	**6,726**

Realisations and profitability

While the Group operates as a single business segment, management estimates the relative profitability by cash generating unit as follows:

	H1 2019		H1 2018	
US$'000	Oil	Gas, condensate & LPG	Oil	Gas & condensate
Revenue	3,581	22,764	6,278	15,254
MET	(2,063)	(5,160)	(3,420)	(3,819)
Depreciation	(414)	(6,512)	(557)	(3,611)
Production costs	(583)	(3,452)	(856)	(3,748)
Selling expenses	(34)	(2,941)	(61)	(418)
Gross profit net of selling expenses	488	4,699	1,384	3,658

The unit realisations are summarised in the following table:

Net Realisation	H1 2019	H1 2018
Oil & condensate (US$/bbl)	41.32	43.80
LPG (US$/bboe)	24.12	27.88
Gas (US$/mcf)	1.84	1.93

Unit Costs are summarised in the following table:

Unit cost data	2019	2018
Production costs	3.97	5.57
Selling costs	2.93	0.58
MET	7.11	8.76

Depletion, depreciation and amortisation	6.82	5.04

The changes in unit costs have occurred for the following reasons:

- Fixed costs being shared over a larger amount of total production led to lower unit production costs;
- MET rates have increased as the oil price increased as well as further upward revisions to the MET rate formula;
- Unit Depletion, depreciation and amortization ("DD&A") rates reflect management's preliminary estimate of reserve revisions, with the depletion pool being spread over a lower reserve number.

Cash flow

Cash flow from operating activities before working capital movements in H1 2019 was US$9.7 million (H1 2018: US$10.3 million), reflecting EBITDA. The H1 2018 number included the court award included in other income. After net working capital outflow of US$0.7 million in H1 2019 (H1 2018: net inflow of US$49,000), and income tax payments of US$1.6 million (H1 2018: US$21,000), net cash inflow from operations was US$7.4 million (H1 2018: US$10.4 million).

Capital Expenditure

For the six months ended 30 June 2019, the Group incurred capital expenditures of US$3.6 million (H1 2018: US$1.8 million), including the sidetracks on VM#2 and Uzen #4, start of the slim hole drilling activities and some expenditure on the gas plant. With settlements of accounts payable for capital expenditure, cash used in the purchase of PP&E and exploration and evaluation during H1 2019 was US$3.3 million (H1 2018: US$2.0 million). There were additions of US$163,000 to intangible assets, incurred on exploration and evaluation, during H1 2019 (H1 2018: nil).

Cash Position and Balance Sheet

During H1 2019, the Company paid equity dividends of US$5.2 million (H1 2018: nil) and spent US$356,000 on the purchase of its own shares (H1 2018: nil). The Group repaid the final outstanding balance of its bank loans in February 2019 of US$1.8 million (H1 2018: loan repayments of US$1.0 million). The Group had cash balances at 30 June 2019 of US$12.4 million (31 December 2018: US$15.2 million), and no borrowings (31 December 2018: US$1.7 million).

Dividends

The Directors recommended a final dividend in respect of the year ended 31 December 2018 of US$0.065 per share which was paid on 28 May 2019. No equity dividends were paid during H1 2018. Given the recent operational developments and the need to preserve the Group's financial position, the Directors do not propose to declare an interim dividend for 2019.

Outlook

As outlined above, management has decided to reduce the production rates from the existing wells on the VM field in order to prevent further increases in water breakthrough, pending completion of the technical review and forward development plan for the field. In addition, the anticipated contribution from the Uzen #4 sidetrack is not being realised. Management therefore expects total production for the remainder of 2019 to average 2,830 boepd. Actual production in July and August 2019 averaged 4,633 boepd.

Realised prices for oil and condensate are expected to continue tracking international oil prices as adjusted for export tax and transportation. Sales of oil and condensate continue to be split between the domestic and export markets, with restrained feedstock demand from domestic independent refineries. The contract gas price in Ruble terms increased by 1.4% on 1 July 2019.

Cost cutting measures are in train both in the production and administration departments, but the effect of redundancy payments will be to defer the realised cost benefits to 2020 and beyond. Consequently, production costs in absolute terms are expected to remain close to the levels reported in H1 2019. As DD&A is charged on a unit of production basis and as the unit DD&A rate for 2H 2019, in the absence of further material changes to reserve estimates, is expected to be unchanged, the depreciation charge for 2H 2019 is expected to be lower than in 1H 2019.

The principal capital expenditure planned for H2 2019, is expected to be US$4.8 million, taking the total capital expenditure for the year to US$8.1 million.

The operational focus of management is on the following items:

- stabilising the gas and condensate production asset base,
- increasing oil production from the slim hole drilling on the Uzen field, including the newly discovered resources in the Upper Aptian layer
- Utilizing slim hole drilling to conduct exploration of identified prospects in the Group's Karpenskiy licence area

In addition, management is seeking to deploy its skills and expertise in new venture areas with the aim of establishing, with modest initial investment, a foundation for future growth.

Principle Risks and Uncertainties

The risks described on pages 12-14 of the 2017 Annual Report, a copy of which can be obtained from www.volgagas.com, remain extant.

Forward-Looking Statements

Certain statements in this interim report are forward-looking. Although the Group believes that the expectations reflected in these forward-looking statements are reasonable, it can give no assurance that these expectations will prove to have been correct. Because these statements involve risks and uncertainties, actual results may differ materially from those expressed or implied by these forward-looking statements.

VOLGA GAS plc

IFRS CONDENSED CONSOLIDATED INTERIM FINANCIAL INFORMATION (UNAUDITED)

Group Interim Income Statement (Unaudited)
(presented in US$000, except for profit per ordinary share and number of shares)

Six months ended 30 June	Notes	2019	2018
Revenue		26,345	21,532
Cost of sales	4	(18,183)	(16,011)
Gross profit		**8,162**	**5,521**
Selling Expenses		(2,975)	(479)
General and administrative expenses	5	(2,723)	(2,435)
Write off of development assets and impairments	6	(5,097)	(1,596)
Operating profit/(loss)		**(2,633)**	**1,011**
Interest income		147	187
Other net gains/(losses)	6	(492)	2,957
Profit/(loss) before tax		**(2,978)**	**4,155**
Provision for deferred tax		1,886	(173)
Provision for current tax		(1,382)	(634)
Profit/(loss) attributable to equity holders		**(2,474)**	**3,348**
Basic and diluted profit/(loss) per ordinary share (in US dollars)		(0.0306)	0.041
Weighted average number of shares outstanding		*80,833,822*	*81,017,800*

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

Six months ended 30 June	Notes	2019	2018
Profit/(loss) for the Period		**(2,474)**	**3,348**
Other comprehensive income:			
Currency translation differences		5,179	(5,484)
Total comprehensive income for the period		**2,705**	**(2,163)**

The accompanying notes are an integral part of this condensed consolidated interim financial information.

Group Balance Sheet (Unaudited)
(presented in US$000)

As at	Notes	30 June 2019	31 December 2018
Assets			
Non-current assets			
Intangible assets	7	3,807	3,304
Property, plant and equipment	7	41,011	45,109
Deferred tax assets		1,240	804
Total non-current assets		**46,058**	**49,217**
Current assets			
Cash, cash equivalents and bank deposits		12,376	15,186
Inventories		788	938
Other receivables		2,304	2,381
Total current assets		**15,468**	**18,505**
Total assets		**61,526**	**67,722**

Equity and liabilities
Equity

Share capital		1,485	1,485
Currency translation and other reserves		(84,010)	(89,189)
Accumulated profit		137,263	145,330
Total equity		**54,738**	**57,626**
Long term liabilities			
Asset retirement obligation		398	361
Deferred tax liabilities		636	2,028
Total long term liabilities		**1,034**	**2,389**
Current liabilities			
Bank loan		-	1,660
Accounts payable	8	5,754	6,047
Total current liabilities		**5,754**	**7,707**
Total equity and liabilities		**61,526**	**67,722**

The accompanying notes are an integral part of this condensed consolidated interim financial information.

Group Interim Cash Flow Statement (Unaudited)
(presented in US$000)

		Six months ended 30 June	
	Notes	**2019**	**2018**
Profit/(loss) for the period before tax		**(2,978)**	**4,155**
Less adjustments for:			
Depreciation, depletion and amortization		6,858	4,119
Write-off of development assets and impairment		5,097	1,719
Inventory write-off		(93)	-
Foreign exchange differences		611	80
Other non-cash operating losses/(gains)		224	269
Total effect of adjustments		**12,697**	**6,187**
Net cash flow before working capital movements		**9,719**	**10,342**
(Increase)/decrease in trade and other receivables		296	(146)
Decrease in payables	9	(1,306)	(160)
(Increase)/decrease in inventory		330	355
Working capital changes		**(680)**	**49**
Income taxes paid		(1,591)	(21)
Net cash from operating activities		**7,448**	**10,370**
Cash flows from investing activities			
Purchase of intangible assets (exploration & evaluation)		(64)	-
Purchase of property, plant and equipment		(3,259)	(1,992)
Net cash used in investing activities		**(3,323)**	**(1,992)**
Cash flows from financing activities			
Dividends paid		(5,237)	-
Purchase of own shares		(356)	-
Loans repaid		(1,782)	(971)
Net cash provided/(used) by financing activities		**(7,375)**	**(971)**
Effect of exchange rate changes on cash and cash equivalents			(1,017)

	440	
Net (decrease)/ increase in cash and cash equivalents	**(2,810)**	**6,390**
Cash and cash equivalents at beginning of the period	15,186	8,617
Cash and cash equivalents at end of the period	**12,376**	**15,007**

The accompanying notes are an integral part of this condensed consolidated interim financial information.

Group Interim Statement of Changes in Equity (Unaudited)
(presented in US$000)

	Share Capital	Currency Translation Reserves	Accumulated Profit	Total Equity
Opening equity at 1 January 2019	**1,485**	**(89,189)**	**145,330**	**57,626**
Profit for the period	-	-	(2,474)	**(2,474)**
Dividends paid	-	-	(5,237)	**(5,237)**
Buyback of shares	-	-	(356)	**(356)**
Currency translation differences	-	5,179	-	**5,179**
Closing equity at 30 June 2017	**1,485**	**(84,010)**	**137,263**	**54,738**
Opening equity at 1 January 2018	**1,485**	**(77,403)**	**141,787**	**65,869**
Profit for the period	-	-	3,348	3,348
Currency translation differences	-	(5,484)	-	(5,484)
Closing equity at 30 June 2018	**1,485**	**(82,887)**	**145,135**	**63,733**

The accompanying notes are an integral part of this condensed consolidated interim financial information.

Notes to the IFRS Condensed Consolidated Interim Financial Statements (Unaudited)
(presented in US$000 unless otherwise stated)

1. General information

Volga Gas plc (hereinafter referred to as "Company" or "Volga") is a public liability company registered in England and Wales with registered number 05886534 and quoted on the AIM market of London Stock Exchange plc. The principal activities of the Company and its subsidiaries (hereinafter jointly referred to as the "Group") are the acquisition, exploration and development of hydrocarbon assets and production of hydrocarbons in the Volga Region of the Russian Federation. The Company's registered office is at 6th floor, 65 Gresham Street, London EC2V 7NQ. This condensed consolidated interim financial information was approved for issue on 27 September 2019.

2. Basis of presentation

This condensed consolidated interim financial information for the half-year ended 30 June 2019 has been prepared in accordance with IAS 34, 'Interim financial reporting'. The condensed consolidated interim financial information should be read in conjunction with the annual financial statements for the year ended 31 December 2018, which have been prepared in accordance with IFRSs as adopted by the European Union.

Selected explanatory notes are included to explain events and transactions that are significant to an understanding of the changes in the Financial Position and performance of the group since the last annual consolidated financial statements.

This condensed consolidated interim financial information does not comprise statutory accounts within the meaning of section 434 of the Companies Act 2006. Statutory accounts for the year ended 31 December 2018 were approved by the board of directors on 5 April 2019 and delivered to the Registrar of Companies. The report of the auditor on those accounts was unqualified, did not contain an emphasis of matter paragraph and did not contain any statement under section 498 of the Companies Act 2006.

Except as described below, the accounting policies applied are consistent with those of the annual financial statements for the year ended 31 December 2018, as described in those annual financial statements.

Going-concern basis. The group meets its day-to-day working capital requirements through its cash resources. After making enquiries, the directors have a reasonable expectation that the Group has adequate resources to continue in operational existence for the foreseeable future. The Group therefore continues to adopt the going concern basis in preparing its consolidated interim financial statements.

Exchange rates. The official rate of exchange of the Russian ruble to the US dollar ("USD") at 30 June 2019 and 31 December 2018 was 63.0756 and 69.4706 Russian Rubles to USD 1.00, respectively. Any re-measurement of Russian Ruble amounts to US dollars or any other currency should not be construed as a representation that such Russian Ruble amounts have been, could be, or will in the future be converted into other currencies at these exchange rates.

Taxation. Taxes on income in the interim periods are accrued using the tax rate that would be applicable to expected total annual earnings.

Segmental reporting follows the Group's internal reporting structure. No geographic segmental information is presented as all of the Group's 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.

3. Accounting policies

The accounting policies adopted in the preparation of these condensed interim consolidated financial statements are consistent with those applied and disclosed in the consolidated financial statements for 2018

4. COST OF SALES

Cost of sales is analysed as follows:

Six months ended 30 June	2019 US$ 000	2018 US$ 000
Production expenses	4,035	4,604
Mineral extraction taxes	7,223	7,238
Depletion, depreciation and amortization	6,925	4,169
	18,183	**16,011**

5. GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses are analysed as follows:

Six months ended 30 June	2019 US$ 000	2018 US$ 000
Salaries	1,608	1,569
Taxes other than payroll and MET	21	24
Audit fees	167	151
Legal and Consultancy	455	241
Other	473	450
Total general and administrative expenses	**2,723**	**2,435**

6. OTHER GAINS AND LOSSES, NET

	Six months ended 30 June	
	2019 **US$ 000**	**2018** **US$ 000**
Foreign exchange loss	(611)	(80)
Proceeds of court judgement	-	3,290
Other expense	119	(253)
Total other net income/(expenses)	**(492)**	**2,957**

7. PROPERTY PLANT AND EQUIPMENT AND INTANGIBLE ASSETS

	Property, plant and equipment US$ 000	Intangible assets US$ 000
As at 1 January 2019	**45,109**	**3,304**
Additions	3,609	163
Depreciation and amortisation	(6,858)	-
Write offs of development assets and impairments	(5,123)	-
Exchange adjustment	4,274	340
At 30 June 2019	**41,011**	**3,807**
As at 1 January 2018	**62,329**	**3,756**
Additions	1,779	-
Depreciation and amortisation	(4,119)	-

Write offs	(1,761)	-
Exchange adjustment	(4,905)	(309)
At 30 June 2018	**53,323**	**3,447**

The write off of development assets and impairments comprised the write off of US$1,944,000 (H1 2018: US$1,761,000) of development assets and impairment charges of US$3,153,000 (H1 2018: nil). A final assessment of asset impairment will be made at the 2019 year end on conclusion of an independent evaluation of reserves.

8. ACCOUNTS RECEIVABLE

	30 June 2019 US$ 000	31 December 2018 US$ 000
Prepayments	215	558
Trade receivables	1,620	1,411
VAT recoverable	168	399
Other	300	13
Total accounts receivable	**2,304**	**2,381**

9. ACCOUNTS PAYABLE

	30 June 2019 US$ 000	31 December 2018 US$ 000
Customer advances	368	1,577
Trade payables	1,578	1,085
Taxes other than profit tax	2,694	2,740
Other	1,113	645
Total accounts payable	**5,754**	**6,047**

10. CONTINGENCIES AND COMMITMENTS

The Group has fulfilled all exploration commitments on existing licences. As at 30 June 2019, the Group had contracted to spend US$3.0 million on its remaining capital expenditure programme for 2019, comprising current drilling operations on Uzen, VM field evaluation services and the upgrade of the LPG plant. In addition, as mentioned in the Management Report, the Group is acquiring a slim hold drilling rig for approximately US$0.7 million and proposes to drill two exploration wells before the year end at an estimated total cost of US$0.5-0.7 million. The Group has no other material commitments or further capital expenditures during the year ending 31 December 2019.

11. RELATED PARTY TRANSACTIONS

The Group is controlled by Baring Vostok Private Equity Fund III, Baring Vostok Private Equity Fund IV and Baring Vostok Investments PCI, which own 64.6% of the Company's shares as at 30 June 2018.

Related party transactions are disclosed in Note 23 to the accounts for the year ended 31 December 2018. There were no material related party transactions in the six months to 30 June 2019 nor in the six months to 30 June 2018.

STATEMENT OF DIRECTORS' RESPONSIBILITIES

The directors confirm that this consolidated interim financial information has been prepared in accordance with IAS 34 as adopted by the European Union and that the interim management report includes a fair review of the information required by DTR 4.2.7R and DTR 4.2.8R, namely:

- an indication of important events that have occurred during the first six months and their impact on the set of financial statements, and a description of the principal risks and uncertainties for the remaining six months of the financial year; and
- material related-party transactions in the first six months and any material changes in the related-party transactions described in the last annual report.

The directors of Volga Gas plc are as listed in the Volga Gas plc Annual Report for the year ended 31 December 2018.

By order of the Board

Andrey Zozulya
Chief Executive Officer

Vadim Son
Chief Financial Officer

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