EastCoast Energy

Natural gas solutions in East Africa

EastCoast Energy Corporation
2006 Q1 Interim Report

Financial and Operating Highlights

Three months ended	**31 Mar 2006**	31 Dec 2005	Change	31 Mar 2005	Change
Financial (US$'000 *except where otherwise stated*)					
Total revenue	**2,073**	2,741	(24%)	350	492%
Profit/(loss) before taxation	**266**	864	(69%)	(518)	151%
Netback (US$/mcf)	**2.05**	2.27	(10%)	3.24	(37%)
Working capital	**2,118**	2,211	(4%)	4,895	(57%)
Shareholders' equity	**16,928**	16,662	2%	15,444	10%
Profit/(loss) per share basic and diluted (US$)	**–**	0.02	(100%)	(0.02)	100%
Cash flow per share basic and diluted (US$)	**0.04**	0.07	(43%)	(0.02)	300%
OUTSTANDING SHARES ('000)					
Class A shares	**1,751**	1,751	–	1,751	–
Class B shares	**21,613**	21,513	–	21,513	–
Options	**1,887**	1,987	(5%)	1,987	(5%)
OPERATING					
Additional Gas sold (mmscf) industrial	**230**	299	(23%)	97	137%
Additional Gas sold (mmscf) power	**682**	766	(11%)	–	–
Average price per mcf (US$) industrial	**7.63**	7.86	(3%)	5.23	46%
Average price per mcf (US$) power	**1.79**	2.15	(17%)	–	–

This report contains certain forward-looking statements based on current expectations, but which involve risks and uncertainties. Actual results may differ materially. See page 20 for additional information on the risks and uncertainties. All financial information is reported in U.S. dollars, unless noted otherwise.

Quarter Highlights

- Earned profit before tax of US$0.3 million with net cash flow from operations of US$0.9 million.
- Increased EastCoast's Q1 sales of Additional Gas to Dar es Salaam industrial customers to 2.6 mmscf/d, up 137% over Q1 2005, at an average price of US$7.63/mcf. April sales averaged 3.2 mmscf/d and this is expected to increase through the remainder of Q2. For 2006, East Coast is projecting average industrial gas sales in excess of 4.0 mmscf/d.
- Generated power sector Additional Gas sales of 7.6 mmscf/d at Ubungo under the Interim Agreement with the electricity utility, TANESCO at an average price of US$1.79/mcf.
- Commenced the negotiation of a master agreement with TANESCO, for the supply of gas to 245 MWs of new generation; and 19.5% of the gas requirements of the Ubungo power plant that is currently being supplied under the Interim Agreement. This is projected to increase new Additional Gas sales by up to 61 mmscf/d by Q1 2008 (43 mmscf/d at 70% load).
- Identified a new high potential drilling prospect in the Songo Songo West area. If gas is discovered, the most likely GIIP is 600 bcf with an upside of 1,070 bcf. The prospect is approximately two kilometers west of the existing Songo Songo field and at the same reservoir interval. The Company has commenced the search for a jack up rig to drill the well.
- Conducted infrastructure capacity tests that indicate that the gas processing plant can operate at significantly higher levels than the nameplate capacity of 70 mmscf/d. Initial indications are that a capacity of 105 – 110 mmscf/d can be achieved with additional capital expenditure of US$3-4 million.
- Developed plans to drill a well on the Songo Songo field during 2006/2007 and perform a well intervention on the SS9 offshore well, to increase deliverability from 140 mmscf/d to a forecast 215 mmscf/d.
- Signed four new gas sales contracts for 0.9 mmscf/d. To service this expanded industrial market a 3.6 kilometer spur line is being constructed at a cost of US$0.2 million.

Glossary

Mcf . . . . Thousands of standard cubic feet
Mmscf . . . . Millions of standard cubic feet
Bcf . . . . Billions of standard cubic feet
Tcf . . . . Trillions of standard cubic feet
Mmscf/d . . . . Millions of standard cubic feet per day
1P . . . . Proven reserves
2P . . . . Proven and probable reserves
GIIP . . . . Gas initially in place
Kwh . . . . Kilowatt hour
MW . . . . Megawatt
US$ . . . . U.S. dollars
Cdn$ . . . . Canadian dollars

President & CEO's Letter to Shareholders

During Q1 2006 EastCoast Energy continued to advance the Company's development and growth plans. To be ready to supply increased volumes of Additional Gas to the power sector EastCoast was engaged in commercial negotiations with the electricity utility, TANESCO over the quarter. The negotiations focused on the natural gas that will be needed for 245 MWs of new power generation. Engineering studies of the existing gas transportation infrastructure from Songo Songo Island to Dar es Salaam have been initiated to determine the most reliable and cost effective way to increase gas throughput.

Exploration plans continue to move forward following the Q1 identification of a promising drilling prospect in the Songo Songo West area approximately two kilometers west of the existing Songo Songo field. EastCoast plans to drill an initial exploration well on the prospect in 2007.

Four new contracts to supply natural gas to the Dar es Salaam industries were also signed during Q1. By July 2006, EastCoast estimates that the Company's Additional Gas sales to the industrial sector will exceed 4.5 mmscf/d.

Power sector demand

Faced with ongoing power shortages due to limited hydro generation capacity, Tanzania's electricity utility, TANESCO, is pushing ahead with the conversion of the 100 MW IPTL power plant at Dar es Salaam. Until the IPTL conversion is fully completed, TANESCO is to lease a 100 MW plant. A 45 MW unit is also planned for Tegeta, and the purchase of an additional 100 MW plant is expected to follow. The recent rainy season has provided some short term relief for the reservoirs that supply TANESCO's hydro power generating facilities, but it is still anticipated that load shedding will resume in June 2006.

To fuel the new power plants, gas supply will need to increase by up to 61 mmscf/d (43 mmscf/d at 70% load). Meeting this demand will represent a significant step change for EastCoast. The increase in the required supply of Additional Gas is expected by the first quarter of 2008.

The need for larger volumes of Additional Gas for the power sector means that the total volume of gas to be transported from Songo Songo could peak at 125 mmscf/d by Q1 2008. The current nameplate infrastructure capacity of 70 mmscf/d is adequate to meet current contracted utility and industrial sales of Additional Gas and up to, but not more than, 45 mmscf/d required by the Protected Gas users.

To increase the capacity of the pipeline system, EastCoast has contracted Petrofac Engineering Limited to assess ways to significantly add throughput. The preliminary Petrofac report indicates that 105-110 mmscf/d could be transported through the existing process facilities and pipeline for an additional investment of approximately US$3-4 million with a lead time of 40 weeks. The plant has already operated under test satisfactorily at 110 mmscf/d and the additional capacity is required to increase reliability at sustained higher rates. This is now under discussion with the Ministry of Energy and Minerals and Songas Limited to see if the nameplate capacity of the plant can be re-certified. A third gas processing train may still be required if peak demand can not be met from the gas contained in the pipeline system or compression.

Songo Songo field development

EastCoast intends to drill a development well on the Songo Songo field during the next 12 months and perform a fishing operation/workover on the offshore well, SS9, to increase deliverability from 140 mmscf/d to approximately 215 mmscf/d. This will ensure security of supply in the event of the failure of any single well at the higher rates planned.

The new development well is planned to be drilled as a deviated well from Songo Songo Island, thereby reducing the drilling and tie-in costs to approximately US$8 million. When drilling the new development well the Company intends to also test a further structure in the Eocene which has previously flowed gas and could add new reserves if successful. The SS9 well workover is estimated to cost approximately US$2 million.

Exploration progress

Reserves and deliverability need to be ahead of demand so that significant commitments to power and infrastructure developments can be planned with greater certainty. During Q1, EastCoast continued to analyse and interpret the 917 kilometers of seismic that was acquired in Q4 2005 and to assess the best drilling strategy given the need to meet the demands of the forthcoming power contracts and to generate additional reserves.

The most significant exploration result in Q1 was the delineation of the Songo Songo West prospect approximately 2 kilometers west of the existing Songo Songo field. If gas is discovered, the most likely GIIP is 600 bcf (compared with current certified 2P Additional Gas recoverable reserves of 320 bcf in the Songo Songo field) with an upside potential of 1,070 bcf. EastCoast intends to drill at least one well on the northern aspect of this structure in the next 12 - 18 months and is currently undertaking a search for a shallow water jack-up rig. A rig inspection team has been working for EastCoast in this regard. It is anticipated that any commercial gas reserves discovered at Songo Songo West will be absorbed in the Tanzanian market.

As reported at the year end, a lead was identified on the seven adjoining blocks ("Adjoining Blocks") but it was assessed as relatively small with a high degree of risk. Accordingly, the Company informed the Ministry of Energy and Minerals on 24 May 2006 that it does not intend to drill a well on the Adjoining Blocks by April 2007 and that it has relinquished the acreage to concentrate on the higher prospectivity of Songo Songo West which has no drilling obligation under the PSA. The relinquishment of this acreage has no impact on the rights of the Company to the Songo Songo field or on Songo Songo West.

Work continues on processing and interpreting 328 kilometers of new seismic that was shot on part of the Nyuni licence acreage ("Area A") subject to the terms of the Nyuni farm-in agreement between EastCoast and a subsidiary of Aminex plc. Under the terms of the agreement, the Company has until 30 September 2006 to elect whether or not to participate in the drilling of a well on Area A. TPDC has indicated that it may not be possible to split out Area A from the remainder of the Nyuni Production Sharing Agreement ("Nyuni PSA"). Accordingly, the Company is in discussion with Aminex plc with respect to transferring the work undertaken on Area A into an equitable interest in the Nyuni PSA.

Q1 sales of Additional Gas

The industrial market at Dar es Salaam is developing well with sales of 0.2 mmscf/d commencing to two new customers, Mukwano Industries (T) Limited and Tanzania Cigarette Company Ltd. Two new contracts were also signed during Q1 with East Coast Oils and Fats Limited and Serengeti Breweries Limited. These new customers will add an additional 0.1 mmscf/d during Q2 2006 increasing to 0.7 mmscf/d by the end of Q4 2006. A 3.6 kilometers spur line is in the process of being constructed to connect these customers at a cost of US0.2 million. In addition, Lakhani Industries Limited Textile and Murzah Oil Mills Limited were connected to the gas distribution system in Q1 and will commence gas consumption at the end of May 2006 at a rate of 0.5 mmscf/d. By July 2006, the Company forecasts that gas sales to the industrial sector will exceed 4.5 mmscf/d.

Additional contracts are currently under discussion for a further 0.7-1.0 mmscf/d of industrial sales and a number of our customers are considering expanding their existing facilities. To meet this demand and ensure security of supply, the Company plans to expand the capacity of the existing distribution system by installing an additional pressure reduction station at a cost of approximately US$2.5 million. This work is scheduled to begin in the second half of 2006.

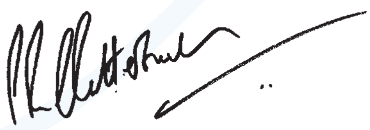
In addition to its industrial sales, EastCoast continues to supply 19.5% of the gas consumption of the six turbines at the Ubungo Power Plant. However, in February a transformer breakdown at Ubungo on turbines 5 and 6 reduced gas sales. The breakdown was repaired by the end of March and sales returned to normalized levels in April.

Outlook

At 31 March, 2006 EastCoast was in a strong financial position with working capital of US$2.1 million. Over Q2 the Company is projecting increased industrial and power sector gas sales. This will enable EastCoast to continue to finance its immediate work commitments and longer lead time items before needing to raise funds to finance the 2007 development and exploration programme.

Your Company is committed to developing new production and additional markets for natural gas in East Africa. Success over the next 18 months will open up new exploration and development opportunities for the Company, both in Tanzania and elsewhere.

The recent surge in oil and gas exploration activities, both onshore and offshore East Africa, is gaining momentum and your Company is well placed to access these opportunities. We value the ongoing confidence of our shareholders and are confident we can continue to add long term value to the benefit of all. This is an exciting time and EastCoast has great potential for growth.



Peter R. Clutterbuck
President & CEO

30 May 2006

Management's Discussion & Analysis

Management's Discussion & Analysis

THIS MDA OF FINANCIAL CONDITIONS AND RESULTS OF OPERATIONS SHOULD BE READ IN CONJUNCTION WITH THE COMPANY'S UNAUDITED FINANCIAL STATEMENTS FOR THE THREE MONTHS ENDED 31 MARCH 2006 AND THE AUDITED FINANCIAL STATEMENTS AND RELATED NOTES FOR THE YEAR ENDED 31 DECEMBER 2005. THIS MDA IS BASED ON THE INFORMATION AVAILABLE ON 30 MAY 2006. IT CONTAINS CERTAIN FORWARD-LOOKING STATEMENTS THAT INVOLVE -SUBSTANTIAL KNOWN AND UNKNOWN RISKS AND UNCERTAINTIES, CERTAIN OF WHICH ARE BEYOND EASTCOAST'S CONTROL, INCLUDING THE IMPACT OF GENERAL ECONOMIC CONDITIONS IN THE AREAS IN WHICH THE COMPANY OPERATES, CIVIL UNREST, INDUSTRY CONDITIONS, CHANGES IN LAWS AND REGULATIONS INCLUDING THE ADOPTION OF NEW ENVIRONMENTAL LAWS AND REGULATIONS AND CHANGES IN HOW THEY ARE INTERPRETED AND ENFORCED, INCREASED -COMPETITION, THE LACK OF AVAILABILITY OF QUALIFIED PERSONNEL OR MANAGEMENT, FLUCTUATIONS IN COMMODITY PRICES, FOREIGN EXCHANGE OR INTEREST RATES, STOCK MARKET VOLATILITY AND OBTAINING REQUIRED APPROVALS OF REGULATORY AUTHORITIES. IN ADDITION THERE ARE RISKS AND UNCERTAINTIES ASSOCIATED WITH GAS OPERATIONS. THEREFORE, EASTCOAST'S ACTUAL RESULTS, PERFORMANCE OR ACHIEVEMENT COULD DIFFER MATERIALLY FROM THOSE EXPRESSED, OR IMPLIED BY, THESE FORWARD-LOOKING ESTIMATES AND, ACCORDINGLY, NO ASSURANCES CAN BE GIVEN THAT ANY OF THE EVENTS ANTICIPATED BY THE FORWARD LOOKING ESTIMATES WILL -TRANSPIRE OR OCCUR, OR IF ANY OF THEM DO SO, WHAT BENEFITS, INCLUDING THE AMOUNTS OF PROCEEDS, THAT EASTCOAST WILL DERIVE THEREFROM.

THE COMPANY EVALUATES ITS PERFORMANCE BASED ON EARNINGS AND CASH FLOWS. CASH FLOW FROM OPERATING ACTIVITIES IS A NON-GAAP (GENERALLY ACCEPTED ACCOUNTING PRINCIPLES) TERM THAT REPRESENTS EARNINGS BEFORE DEPLETION, DEPRECIATION AND STOCK-BASED COMPENSATION. IT IS A KEY MEASURE AS IT DEMONSTRATES THE COMPANY'S ABILITY TO GENERATE CASH NECESSARY TO ACHIEVE GROWTH THROUGH CAPITAL INVESTMENTS. EASTCOAST ALSO ASSESSES ITS PERFORMANCE UTILIZING OPERATING NETBACKS. OPERATING NETBACKS REPRESENT THE PROFIT MARGIN ASSOCIATED WITH THE PRODUCTION AND SALE OF ADDITIONAL GAS AND IS CALCULATED AS REVENUES LESS RINGMAIN TARIFF, GOVERNMENT PARASTATAL'S REVENUE SHARE, OPERATING AND DISTRIBUTION COSTS. THESE NON-GAAP MEASURES ARE NOT STANDARDISED AND THEREFORE MAY NOT BE COMPARABLE TO SIMILAR MEASUREMENTS OF OTHER ENTITIES.

ADDITIONAL INFORMATION REGARDING EASTCOAST ENERGY CORPORATION IS AVAILABLE UNDER THE COMPANY'S PROFILE ON SEDAR AT www.sedar.com.

Background

EastCoast Energy Corporation's ("EastCoast" or the "Company") principal asset is its interest in a Production Sharing Agreement ("PSA") with the Tanzania Petroleum Development Corporation ("TPDC") in Tanzania. This PSA covers the production and marketing of certain gas from the Songo Songo gas field.

The gas in the Songo Songo field is divided between Protected Gas and Additional Gas. The Protected Gas is owned by TPDC and is sold under a 20-year gas agreement to Songas Limited ("Songas"). Songas is the owner of the infrastructure that enables the gas to be delivered to Dar es Salaam, namely a gas processing plant on Songo Songo Island, 232 kilometers of pipeline to Dar es Salaam and a 16 kilometer spur to the Wazo Hill cement plant.

Songas utilises the Protected Gas (maximum 45.1 mmscf/d) as feedstock for its gas turbine electricity generators at Ubungo, for onward sale to the Wazo Hill cement plant and for electrification of some villages along the pipeline route. EastCoast receives no revenue for the Protected Gas delivered to Songas and operates the field and gas processing plant on a 'no gain no loss' basis.

EastCoast has the right to produce and market all gas in the Songo Songo field in excess of the Protected Gas requirements ("Additional Gas").

Principal terms of the PSA and related agreements

The principal terms of the Songo Songo PSA and related agreements are as follows:

Obligations and restrictions

(a) The Company has the right to conduct petroleum operations, market and sell all Additional Gas produced and share the net revenue with TPDC for a term of 25 years expiring in October 2026.

(b) The PSA covers the two licences in which the Songo Songo field is located ("Discovery Blocks") and the seven licences adjoining the Discovery Block ("Adjoining Blocks"). Together the Discovery Blocks and Adjoining Blocks are the Contract Area.

The Proven Section is essentially the area covered by the Songo Songo field within the Discovery Blocks.

(c) The Company's right regarding the Adjoining Blocks was for the period from October 2001 to October 2005 (extended to 11 January 2006 at the request of TPDC to the Ministry of Energy and Minerals ("MEM") and further extended to 30 April 2006 by MEM). During this period, the Company was required to conduct a market survey, spend at least US$2.0 million (in October 2001 terms) on seismic or other field expenditures acceptable to TPDC, commit to drill one exploration well in the Adjoining Blocks, demonstrate to MEM compliance with submitted Additional Gas plans and make diligent attempts to sell Additional Gas. The Company acquired 377 kilometers of 2D seismic on the Adjoining Blocks during October 2005 using the Geomariner survey vessel and the interpretation of the seismic revealed a small accumulation ("Lead A") that was considered high risk. Accordingly, the Company informed the MEM on 24 May 2006 that it does not intend to drill a well on the Adjoining Blocks and that it has relinquished the acreage to concentrate on the higher prospectivity of Songo Songo West. The relinquishment of this acreage has no impact on the rights of the Company to the Songo Songo field or on Songo Songo West.

(d) No sales of Additional Gas may be made from the Discovery Blocks if in EastCoast's reasonable judgement such sales would jeopardise the supply of Protected Gas. Any Additional Gas contracts entered into prior to 31 July 2009 are subject to interruption. Songas has the right to request that the Company and TPDC obtain security reasonably acceptable to Songas prior to making any sales of Additional Gas from the Discovery Block to secure the Company's and TPDC's obligations in respect of Insufficiency (see (f) below).

Songas has written to EastCoast confirming that, subject to certain conditions, security will not be required for the supply of Additional Gas to the Ubungo Power Plant, for the supply of up to 15 mmscf/d for a period of five years for additional power generation and up to 10 mmscf/d for the industrial sector.

The Company has written to Songas requesting clarification of their intention with respect to security for the additional 245 MWs of new generation that TANESCO intends to install in Dar es Salaam during 2006/2007.

(e) By 31 July 2009, the Government of Tanzania ("GoT") can request EastCoast to sell 100 bcf of Additional Gas for the generation of electricity over a period of 20 years from the start of its commercial use, subject to a maximum of 6 bcf per annum or 20 mmscf/d ("Reserved Gas"). In the event that the GoT does not nominate by 31 July 2009 or consumption of the Reserved Gas has not commenced within three years of the nomination date, then the reservation shall terminate. Where Reserved Gas is utilised, TPDC and the Company will receive a price that is no greater than 75% of the market price of the lowest cost alternative fuel delivered at the facility to receive Reserved Gas or the price of the lowest cost alternative fuel at Ubungo.

(f) "Insufficiency" occurs if there is insufficient gas from the Discovery Blocks to supply the Protected Gas requirements or is so expensive to develop that its cost exceeds the market price of alternative fuels at Ubungo.

Where there have been third party sales of Additional Gas by EastCoast and TPDC from the Discovery Blocks prior to the occurrence of the Insufficiency, then EastCoast and TPDC shall be jointly liable for the Insufficiency and shall satisfy its related liability by either replacing the Indemnified Volume (as defined in (g) below) at the Protected Gas price with natural gas from other sources; or by paying money damages equal to the difference between: (a) the market price for a quantity of alternative fuel that is appropriate for the five gas turbine electricity generators at Ubungo ("Complex") without significant modification together with the costs of any modification; and (b) the sum of the price for such volume of Protected Gas (at US$0.55/mmbtu) and the amount of transportation revenues previously credited by Songas to the electricity utility, TANESCO, for the gas volumes.

(g) The "Indemnified Volume" means the lesser of the total volume of Additional Gas sales supplied from the Discovery Blocks prior to an Insufficiency and the Insufficiency Volume. "Insufficiency Volume" means the volume of natural gas determined by multiplying the average of the annual Protected Gas volumes for the three years prior to the Insufficiency (where the fifth turbine has been installed, but has not been operational for three years an imputed amount of annual gas consumption for the fifth turbine is incorporated) by 110% and multiplied by the number of remaining years (initial term of 20 years) of the power purchase agreement entered into between Songas and TANESCO in relation to the five gas turbine electricity generators at Ubungo from the date of the Insufficiency.

Access and development of infrastructure

(h) The Company is able to utilise the Songas infrastructure including the gas processing plant and main pipeline to Dar es Salaam. The pipeline and gas processing plant is open access and can be utilised by any third party who wishes to process or transport gas.

Songas is not required to incur capital costs with respect to additional processing and transportation facilities unless the construction and operation of the facilities are, in the reasonable opinion of Songas, financially viable. If Songas is unable to finance such facilities, Songas shall permit the seller of the gas to construct the facilities at its expense, provided that, the facilities are designed, engineered and constructed in accordance with good pipeline and oilfield practices.

Revenue sharing terms and taxation

(i) 75% of the gross revenues less pipeline tariffs and direct sales taxes in any year ("Net Revenues") can be used to recover past costs incurred. Costs recovered out of Net Revenues are termed Cost Gas.

The Company pays and recovers all costs of exploring, developing and operating the Additional Gas with two exceptions: (i) TPDC may recover reasonable market and market research costs as defined under the PSA; and (ii) TPDC has the right to elect to participate in the drilling of at least one well for Additional Gas in the Contract Area for which there is a development program as detailed in the Additional Gas plans as submitted to the Ministry of Energy and Minerals ("Additional Gas Plan") subject to TPDC being able to elect to participate in a development program only once and TPDC having to pay a proportion of the costs of such development program by committing to pay between 5% and 20% of the total costs ("Specified Proportion"). If TPDC does not notify the Company within 90 days of notice from the Company that the Ministry of Energy and Minerals has approved the Additional Gas Plan, then TPDC is deemed not to have elected. If TPDC elects to participate, then it will be entitled to a rateable proportion of the Cost Gas and their profit share increases by the Specified Proportion for that development program.

The Company forecasts that TPDC may elect to participate in the forthcoming drilling of new wells and the related infrastructure development.

(j) The price payable to Songas for the general processing and transportation of the gas is 17.5% of the price of gas delivered to a third party less any direct taxes payable by the customer that are included in the gas price less any tariffs paid for non-Songas owned distribution facilities ("Songas Outlet Price").

In September 2001, the GoT made a formal request to the World Bank for funds to increase the diameter of the onshore pipeline from 12 inches to 16 inches at a projected incremental cost of US$3.5 million. The World Bank agreed to finance this increase and accordingly the pipeline capacity was increased from circa 65 mmscf/d to in excess of 105 mmscf/d. The tariff that is payable to GoT for this incremental capacity has yet to be agreed, but the Company has assumed it will be 17.5% of the Songas Outlet Price.

(k) The cost of maintaining the wells and flowlines is split between the Protected Gas and Additional Gas users in proportion to the volume of their respective sales. The cost of operating the gas processing plant and the pipeline to Dar es Salaam is covered through the payment of the pipeline tariff.

(l) Profits on sales from the Proven Section ("Profit Gas") are shared between TPDC and the Company, the proportion of which is dependent on the average daily volumes of Additional Gas sold or cumulative production.

The Company receives a higher share of the Net Revenues after cost recovery, the higher the cumulative production or the average daily sales, whichever is higher. The profit share is a minimum of 25% and a maximum of 55%.

Average daily sales of Additional Gas mmscf/d	Cumulative sales of Additional Gas bcf	TPDC’s share of Profit Gas %	Company’s share of Profit Gas %
0 - 20	0 - 125	75	25
>20 <=30	>125<=250	70	30
>30 <=40	>250<=375	65	35
>40 <=50	>375<=500	60	40
>50	>500	45	55

For Additional Gas produced outside of the Proven Section, the Company’s profit share is 55%.

Where TPDC elects to participate in a development program, their profit share increases by the Specified Proportion (for that development program).

The Company is liable to income tax. Where income tax is payable, there is a corresponding deduction in the amount of the Profit Gas payable to TPDC.

(m) Additional Profits Tax is payable where the Company has recovered its costs plus a specified return out of Cost Gas revenues and Profit Gas revenues. As a result: (i) no Additional Profits Tax is payable until the Company recovers all its costs out of Additional Gas revenues plus 25% plus the percentage change in the United States Industrial Goods Producer Price Index (“PPI”) annual return; and (ii) the maximum Additional Profits Tax rate is 55% of the Company’s profit share when costs have been recovered with a 35% plus PPI return. The PSA is, therefore, structured to encourage the Company to develop the market and the gas fields in the knowledge that the profit share can increase with larger daily gas sales and that the costs will be recovered with a 25% plus PPI annual return before Additional Profits Tax becomes payable. Additional Profits Tax can have a significant negative impact on the project economics if only limited capital expenditure is incurred.

Operatorship

(n) The Company is appointed to develop, produce and process Protected Gas and operate and maintain the gas production facilities and processing plant, including the staffing, procurement, capital improvements, contract maintenance, maintain books and records, prepare reports, maintain permits, handle waste, liaise with GoT and take all necessary safe, health and environmental precautions all in accordance with good oilfield practices. In return, the Company is paid or reimbursed by Songas so that the Company neither benefits nor suffers a loss as a result of its performance.

(o) In the event of loss arising from Songas’ failure to perform and the loss is not fully compensated by Songas, EastCoast, CDC or insurance coverage, then EastCoast is liable to a performance and operation guarantee of US$2,500,000 when (i) the loss is caused by the gross negligence or wilful misconduct of the Company, its subsidiaries or employees, and (ii) Songas has insufficient funds to cure the loss and operate the project.

Consolidation

The companies that are being consolidated are:

Company	Incorporated
EastCoast Energy Corporation	British Virgin Islands
PAE PanAfrican Energy Corporation	Mauritius
PanAfrican Energy Tanzania Limited	Jersey

Q1 Results

Revenue and Operating Costs

Under the terms of the PSA with TPDC, EastCoast is responsible for invoicing, collecting and allocating the revenue from Additional Gas sales.

EastCoast is able to recover all costs incurred on the development and administration of the project out of 75% of the Net Revenues. Any costs not recovered in any period are carried forward to be recovered out of future revenues. Revenue less cost recovery is allocated 75% to TPDC and 25% to EastCoast.

EastCoast had recoverable costs throughout the period and accordingly was allocated 81.25% of the Net Revenues as follows:

	Three months ended		
(US$'000 *except production and per mcf data*)	**31 Mar 2006**	31 Dec 2005	31 Mar 2005
Gross sales volume (mcf):			
Industrial sector	**230**	299	97
Power sector	**682**	766	–
Total volumes	**912**	1,065	97
Average sales price (US$/mcf):			
Industrial sector	**7.63**	7.86	5.23
Power sector	**1.79**	2.15	–
Average price	**3.26**	3.76	5.23
Gross sales revenue	**2,975**	4,001	507
Gross tariff for processing plant and pipeline infrastructure	**471**	641	76
Gross revenue after tariff	**2,504**	**3,360**	**431**
Analysed as to:			
Company Cost Gas	**1,877**	2,520	323
Company Profit Gas	**157**	210	27
Company operating revenue (see Note 1)	**2,034**	**2,730**	**350**
TPDC Profit Gas	**470**	630	81
	2,504	**3,360**	**431**
Production and distribution expenses			
Ring main distribution pipeline	**70**	72	23
Share of well maintenance	**45**	82	3
Other field and operating costs	**50**	166	10
Production and distribution expenses	**165**	320	36
Depletion	**324**	375	29

Note 1 *The Company's total revenues for the quarter amounted to* US$2,073,000 *after adjusting the Company's operating revenue of* US$2,034,000 *by:*

i) US$67,000 *for income tax. The Company is liable for income tax in Tanzania, but the income tax is recoverable out of* TPDC's *Profit Gas when the tax is payable. To account for this, revenues are grossed up for the income tax and the tax is shown separately;*

ii) US$28,000 *for the deferred effect of Additional Profit Tax. This tax is deducted from revenue as a royalty.*

Volumes

Industrial

During the quarter, sales volumes decreased by 23% from the previous quarter. This was anticipated as the textile customers historically cut back production for maintenance during this period. Textile customers form a significant part of the industrial sales. Decrease in their gas consumption offsetted the impact of two new customers, Tanzania Cigarettes Company Limited and Mukwano Industries Limited, who started consumption during the quarter at a rate of 0.12 mmscf/d. Industrial sales averaged 2.5 mmscf/d (Q4 2005: 3.3 mmscf/d) and peaked at 3.2 mmscf/d in January 2006. Textile customers started to recover in Q2 and are expected to peak in Q3 following the cotton harvest season.

Power

An Interim Agreement with Songas Limited for the sale of Additional Gas to Ubungo Power Plant was signed on 1 October 2005. In accordance with the terms of the Interim Agreement, 19.5% of the gas volumes supplied to the six turbines at Ubungo Power Plant is considered Additional Gas. The Interim Agreement expired on 31 December 2005, but the parties agreed to extend its terms to 31 May 2006 to allow for time to negotiate a longer term agreement within the context of increasing demand by the power sector for a number of different projects. It is likely that this Interim Agreement will be further extended to 31 August 2006 when a longer term contract should be signed.

The Additional gas sales to the Ubungo Power Plant decreased by 11% to 682 mmscf (Q4 2005: 766 mmscf) due to the breakdown of the transformers for UGT 5 and UGT 6 on 18 February 2006. The faulty transformers were replaced in late March and gas consumption resumed to normal levels in April. Consumption averaged 7.6 mmscf/d (Q4 2005: 8.3 mmscf/d) during the quarter.

Pricing

Industrial

The price of gas for the period for the industrial sector was at a discount to the price of Heavy Fuel Oil ("HFO") in Dar es Salaam. This resulted in average gas prices of US$7.63/mcf (Q4 2005: US$7.86/mcf) during Q1.

The gas price achieved for the industrial sector will fluctuate with world oil prices and the discount agreed with the customers. The monthly range of Additional Gas price sold to industrial customers in Dar es Salaam during the three months ended 31 March 2006 was US$7.35/mcf to US$ 7.97/mcf.

Power

The Interim Agreement for the sale of Additional Gas to the Ubungo Power Plant provided for different gas prices, depending on the average availability of the six turbines, from the minimum of US$0.67/mbtu (US$0.62/mcf) to the maximum of US$2.32/mbtu (US$2.15/mcf). As a result of the failure of two gas turbines and consequent decrease in gas consumption, the Company realised an average price of US$2.32/mbtu for January and US$1.67/mbtu for February and March.

Consumers currently pay approximately 7.5 cents/kwh for their electricity. This tariff is the lowest in East Africa and significantly lower than the current prices in western economies. This will limit the price that gas can be sold to the power sector. Accordingly, Gas prices to the power sector are forecast to average US$2.15-US$2.30/mcf rising annually in accordance with a pre-agreed formula.

Tariff

The tariff is calculated as 17.5% of the price of gas at the Songas main pipeline in Dar es Salaam ("Songas Outlet Price"). In calculating the Songas Outlet Price for the industrial customers, an amount of US$1.24/mcf ("Ringmain Tariff") has been deducted from the achieved sales price of US$7.63/mcf (Q4 2005: US$7.86/mcf) to reflect the gas price that would be achievable at the Songas main pipeline. The Ringmain tariff represents the amount that would be required to compensate a third party distributor of the gas for constructing the connections from the Songas main pipeline to the industrial customers. No deduction has been made for sales to the power sector since the gas is not transported through the Company's own infrastructure.

Production and Distribution Expenses

The cost of maintaining the ring main distribution pipeline and pressure reduction station (security, insurance and personnel) is forecast to be approximately US$0.2 million per annum in its current form.

The well maintenance costs are allocated between Protected and Additional Gas based on the proportion of their respective sales during the year. The total costs for the maintenance for the period was US$225,000 (Q4 2005: US$69,000) and US$45,000 (Q4 2005: US$82,000) was allocated for the Additional Gas. The production and distribution expenses in Q4 2005 were higher than normal as it included some reserve evaluation costs that had previously been capitalized.

Other operating costs include an apportionment of the annual PSA licence costs and some costs associated with the evaluation of the reserves.

Operating Netbacks

The netback per mcf before general and administrative costs, overheads, tax and Additional Profits Tax may be analysed as follows:

	Three months ended		
(*Amounts in US$/mcf*)	31 Mar 2006	31 Dec 2005	31 Mar 2005
Gas price – industrial	7.63	7.86	5.23
Gas price – power	1.79	2.15	–
Average price for gas	**3.26**	**3.76**	**5.23**
Tariff (after allowance for the Ringmain Tariff)	(0.52)	(0.60)	(0.78)
TPDC Profit Gas	(0.51)	(0.59)	(0.84)
Net selling price	**2.23**	**2.57**	**3.61**
Well maintenance and other operating costs	(0.10)	(0.22)	(0.13)
Ringmain distribution pipeline costs	(0.08)	(0.08)	(0.24)
Netback	**2.05**	**2.27**	**3.24**

Netbacks were lower in Q1 2006 and Q4 2005 against Q1 2005 as sales to the power sector sales are at lower prices than industrial sales and the industrial sales as a percentage of total sales decreased during Q1 2006. The decrease in Additional Gas sales prices to Ubungo Power Plant in February and March resulted in a further decline in netback during the period against Q4 2005.

The netbacks are forecast to increase in Q2 2006 as the volumes to the industrial and power sectors increase and the price achieved for gas sales to the power sector return to the levels experienced in Q4 2005.

The netbacks are currently benefiting from the recovery of 75% of the Net Revenues as Cost Gas.

General and Administrative Expenses

The general and administrative expenses ("G&A") may be analysed as follows:

(*Figures in* US$'000)	Three months ended 31 Mar 2006	31 Dec 2005	31 Mar 2005
Employee costs	**333**	199	188
Stock based compensation	**96**	170	71
Travel & accommodation	**72**	57	55
Communications	**21**	23	18
Office	**110**	129	84
Consultants	**228**	257	141
Insurance	**36**	22	42
Auditing & taxation	**51**	51	19
Depreciation	**27**	27	25
Marketing costs including legal fees	**184**	133	–
Reporting, regulatory and corporate finance	**118**	100	128
Directors' fees	**17**	22	14
Total general and administrative expenses	**1,293**	**1,190**	**785**

G&A averaged approximately US$0.43 million per month (including the stock-based compensation and depreciation) during the period (Q4 2005: US$0.40 million). The cost per gross mcf sold increased during the quarter to US$1.42/mcf (Q4 2005: US$1.12/mcf) due to the decrease in sales to both the industrial and power sectors. The G&A per mcf is expected to fall in Q2 2006 with an increase in sales as a large proportion of the G&A is relatively fixed in nature.

The Company uses the Black-Scholes option pricing model in determining the fair value of options. The monthly charge was revised to US$32,000 in Q4 2005 to reflect the likelihood that more beneficiaries will exercise options granted to them. The revised amount will continue to be charged to the income statement until all options have vested in September 2006.

Taxes

Under the terms of the PSA, the Company is liable to Tanzanian income tax. However, this is recovered from TPDC by deducting an amount from TPDC's profit share. On receipt of any Profit Gas under the PSA, the Company's revenue will be grossed up for associated income tax.

The Company and TPDC are seeking clarification from the Commissioner of Taxes as to how it intends to treat the capitalised expenses for tax purposes as there appears to be some conflict between the language of the PSA and the Tanzanian Income Tax Act 2004. The principal difference is whether the capitalised costs will be written off (PSA language) or capitalised over a few years (per the Income Tax Act 2004). US$70,000 is payable as income tax for the quarter ended 31 March 2006 (cumulative to 31 March 2006: US$129,000) in the event that the Commissioner of Taxes follows the Income Taxes Act 2004. No tax will be payable if it is determined that there should be an acceleration in the write off of the capitalised expenses.

As at 31 March 2006, there were temporary differences between the carrying value of the assets and liabilities for financial reporting purposes and the amounts used for taxation purposes under the Income Tax Act 2004. Applying the 30% Tanzanian tax rate, the Company has recognised a deferred tax liability of US$619,000. This tax has no impact on cash flow until it becomes a current income tax at which point the tax is paid to the Commissioner of Taxes and recovered from TPDC.

Additional Profits Tax

Under the terms of the PSA, in the event that all costs have been recovered with an annual return of 25% plus the percentage change in the United States Industrial Goods Producer Price Index, an Additional Profits Tax ("APT") is payable.

The Company provides for APT by forecasting the total APT payable as a proportion of the forecast Profit Gas over the term of PSA licence. As at 31 March 2006, the effective APT rate was calculated to be 18%. Accordingly, US$28,000 has been deducted from revenue for the quarter.

As at 31 March 2006, there were un-recovered costs of US$12.3 million. Management does not anticipate that any APT will be payable in 2006 as the forecast revenues will not be sufficient to cover the un-recovered costs brought forward as inflated by 25% plus the percentage change in the United States Industrial Goods Producer Price Index and the forecast expenditures for the year. The actual APT that will be paid is dependent on the achieved value of the Additional Gas sales and the quantum and timing of the operating costs and capital expenditure programme.

The APT can have a significant negative impact on the Songo Songo project economics as measured by the net present value of the cash flow streams. Higher revenue in the initial years leads to a rapid payback of the project costs and consequently accelerates the payment of the APT that can account for up to 55% of the Company's profit share. Therefore, the terms of the PSA rewards the Company for taking higher risks by incurring capital expenditure in advance of revenue generation.

Depletion and Depreciation

The Natural Gas Properties are depleted using the unit of production method based on the production for the period as a percentage of the total future production from the Songo Songo proven reserves. As at 31 December 2005, the proven reserves as evaluated by the independent reservoir engineers, McDaniel & Associates Consultants Ltd. ("McDaniel") were 240.6 bcf (2004: 171.2 bcf) on a life of licence basis. This leads to a depletion charge of US$0.36/mcf in Q1 2006 (Q4 2005: US$0.35/mcf).

Non-Natural Gas Properties are depreciated as follows:

Leasehold improvements	Over remaining life of the lease
Computer equipment	3 years
Vehicles	3 years
Fixtures and fittings	3 years

Recoverable Costs

As at 31 March 2006, the Company had US$12.3 million of costs that are recoverable out of 75% of the future Net Revenues.

Carrying Value of Assets

Capitalised costs are periodically assessed to determine whether it is likely that such costs will be recovered in the future. To the extent that these capitalised costs are unlikely to be recovered in the future, they are written off and charged to earnings.

Cash Flow

Pre tax cash flows from operations was US$0.6 million in the period to 31 March 2006. The components of the Company's cash flow were as follows:

	Three months ended		
(*Figures in* US$'000)	31 Mar 2006	31 Dec 2005	31 Mar 2005
Profit/(loss) after taxation	**83**	396	(518)
Adjustment for non cash items	**588**	1,158	125
Cash flows from operations	**671**	**1,554**	**(393)**
Working capital adjustments	**349**	61	(147)
Natural gas properties and other equipment expenditure	**(851)**	(2,902)	(303)
Net proceeds from rights issue and exercise of options	**87**	–	4,375
Net increase/(decrease) in cash and cash equivalent	**256**	**(1,287)**	**3,532**

There was a significant increase in the net cash and cash equivalent in Q1 2005 due to the net receipt of US$4.4 million from the rights issue.

Capital Expenditures

Gross capital expenditures amounted to US$0.9 million in Q1 2006 (Q4 2005: US$2.9 million). The capital expenditure may be analysed as follows:

	Three months ended		
(*Figures in* US$'000)	31 Mar 2006	31 Dec 2005	31 Mar 2005
Geological and geophysical	**514**	1,999	88
Pipelines and infrastructure	**305**	868	210
Power development	–	35	–
Other equipment	**32**	–	5
	851	**2,902**	**303**

During the period, the Company continued to process and interpret data from the seismic acquisition on the Songo Songo licence area and the Nyuni farm-in licence acreage. The Company also started preparation for the drilling of two wells on the Songo Songo field and the exploration prospect and incurred US$188,000 on project management and the ordering of materials.

During the period the Company completed the construction of a 3.6 kilometer spur to Lakhani Industries Limited Textile ("Lakhani"), Murzah Oils Limited ("Murzah"), Mukwano Industries Limited ("Mukwano") and Tanzania Cigarette Company Ltd ("TCC"). Mukwano and TCC started gas consumption during the period at a rate of 0.12mmscf/d. Lakhani and Murzah are expected to start consumption in Q2 2006.

The Company also commissioned a contractor to study ways of maximising throughput of the existing gas processing plant and pipeline infrastructure to meet forecast demand in the next two years. The contractor has indicated the possibility of increasing the production rate to 105-110 mmscf/d from the existing nameplate capacity of 70 mmscf/d with some modifications to the cold separators and gas control valves and the upgrading of the flare system.

Working Capital

Working capital as at 31 March 2006 was US$2.1 million (31 December 2006: US$2.2 million) and may be analysed as follows:

(*Figures in* US$'000)	Three months ended 31 Mar 2006	31 Dec 2005	31 Mar 2005
Cash and cash equivalents	3,454	3,198	5,572
Trade and other receivables	2,044	2,862	495
	5,498	**6,060**	**6,067**
Trade and other payables	3,380	3,849	1,172
Working capital	**2,118**	**2,211**	**4,895**

Under the terms of the PSA and other Songo Songo agreements:

- The profit share owed to TPDC is payable within 30 days of each quarter end. Accordingly, the Company benefits from holding the cash receipts for this period of time and the quarter end cash balance is likely to increase as sales increase. As at 31 March 2006, US$464,000 (31 December 2005: US$629,000) was owed to TPDC.
- Songas advances funds to cover all anticipated expenditure on the gas processing plant and wells in the following month. As at 31 March 2006, US$294,000 (31 December 2005: US$104,000) of cash had been advanced by Songas to cover these operating expenses.
- The tariff for the use of the gas processing plant and pipeline infrastructure is payable to Songas within 30 days of each month end. As at 31 March 2006 the Company owed Songas US$259,000 (31 December 2005: US$420,000) for the tariff.

Also included in cash and cash equivalents was US$110,000 advanced by Lakhani and Murzah as a deposit for their connection. This amount will be repaid to the companies after they have consumed in excess of US$200,000 and US$100,000 of Additional Gas respectively. This amount is included in trade and other payables.

The majority of the cash is held in US and Cdn dollars in Mauritius and in Tanzanian Shillings in Tanzania bank accounts. There are no restrictions in Tanzania for converting Tanzania Shillings into US dollars. Any surplus cash is held in a fixed rate interest earning deposit account.

Under the contract terms with the industrial customers, the Additional Gas payments must be received within 30 days of the month end. As at 31 March 2006, US$0.9 million was due for the month of February and March (including VAT) from the industrial customers. The majority of this has been subsequently received from the industrial customers. Trade and other receivables also includes an amount of US$0.7 million due from Songas for the supply of Additional Gas to the Ubungo Power Plant. The contract with Songas accounted for 40% of the Company's operating revenue during the period. Songas' financial security is heavily reliant on the payment of capacity and energy charges by the electricity utility, TANESCO. TANESCO is currently experiencing financial difficulties principally caused by low rains and the consequential loss of the hydro electricity generation. As a result, TANESCO is dependent on the Government of Tanzania for day to day funding. Whilst payment for March sales remains outstanding, the Company collected all amounts due from Songas for the sales to 28 February 2006. The level of receivables will be closely monitored to minimise any potential default by any of the Company's customers.

Management forecasts that the Company will be able to meet its 2006 capital expenditure programme through the use of existing funds, self generated cash flows and the raising of equity. In addition, the Company has no bank borrowings and there is scope for utilising debt funding once the contracts for the supply of gas to the power sector are in place.

Outstanding Share Capital

There were 23.4 million shares outstanding at 31 March 2006 and may be analysed as follows:

	Three months ended		
No of shares ('000)	31 Mar 2006	31 Dec 2005	31 Mar 2005
SHARES OUTSTANDING			
Class A shares	**1,751**	1,751	1,751
Class B shares	**21,613**	21,513	21,513
	23,364	23,264	23,264
CONVERTIBLE SECURITIES:			
Options	**1,887**	1,987	1,987
Fully diluted Class A and Class B shares	**25,251**	**25,251**	**25,251**

The weighted average shares for the period ended 31 March 2006 were as follows:

WEIGHTED AVERAGE	31 Mar 2006
Class A and Class B shares	**23,325**
Options	**1,358**
Weighted average diluted Class A and Class B shares	**24,683**

A further 20,000 Class B shares were issued on 24 May 2006 when 20,000 options were exercised taking the total Class B shares to 21,633,000 as of the date of this report. No Class A shares have been issued since 31 March 2006.

Stock Based Compensation

The stock option plan provides for the granting of stock options to directors, officers, employees and consultants. Stock options granted have a maximum term of ten years to expiry and vest equally over a two year period commencing 1 September 2004. The exercise price of each stock option is determined as the closing market price of the common shares on the day prior to the day of grant. Each stock option granted permits the holder to purchase one common share at the stated exercise price. In accordance with IFRS2, the Company records a charge to the profit and loss account using the Black & Scholes fair valuation option pricing model. The valuation is dependent on a number of estimates, including the risk free interest rate, the level of stock volatility, together with an estimate of the level of forfeiture.

2,000,000 options were issued to certain Directors and Officers on 1 September 2004 at a price of Cdn$1 per option. During Q1 2006, 100,000 options were exercised. A total of 1,887,400 options remain outstanding as at 31 March 2006.

Contractual Obligations

Under the terms of the PSA, in the event that there is a shortfall in Protected Gas as a consequence of the sale of Additional Gas, then the Company is liable to pay the difference between the price of Protected Gas (US$0.55/mmbtu) and the price of an alternative feedstock multiplied by the volumes of Protected Gas up to a maximum of the volume of Additional Gas sold. Songas has the right to request reasonable security on all Additional Gas sales.

Songas has communicated to EastCoast confirming that, subject to certain conditions, security will not be required for the supply of Additional Gas to the Ubungo Power Plant, for the supply of up to 15 mmscf/d for a period of five years for additional power generation and up to 10 mmscf/d for the industrial sector.

The Company has written to Songas requesting clarification of Songas's intention with respect to security for the additional 245 MWs of new generation that TANESCO intends to install in Dar es Salaam during 2006/2007.

On 21 September 2005, the Company signed an agreement with a subsidiary of Aminex plc to farm-in to 382 square kilometers ("Area A") of the Nyuni Production Sharing Agreement ("Nyuni PSA") that lies adjacent to the Songo Songo field. During October, the Company fulfilled the initial terms of the farm-in agreement by acquiring in excess of 300 kilometers of seismic in Area A. Under the terms of the agreement, the Company has until 30 September 2006 to elect whether or not to participate in the drilling of a well on Area A. If the Company elects to drill, it will pay either 42% to earn a 35% interest in Area A or 64% to earn a 50% interest. TPDC has indicated that it may not be possible to split out Area A from the remainder of the Nyuni PSA. Accordingly, the Company is in discussion with Aminex plc with respect to transferring the work undertaken on Area A into an equitable interest in the Nyuni PSA.

Under the terms of the contracts with Kioo Ltd., Tanzania Breweries Ltd. and Karibu Textile Mills Ltd., the Company is liable to pay penalties in the event that there is a shortfall in the Additional Gas supply in excess of 5% of the contracted quantity. The penalties equate to the difference between the price of gas and an alternative feedstock multiplied by the notional daily quantities. The maximum penalty for shortfall gas is a total of US$1.1 million for these three contracts and the remedy is payable as a credit against future monthly invoices.

Management expects to fund its committed capital investments in 2006 from existing and self generated funds, debt and the raising of equity.

Contingent Liabilities

The Company received two letters in the period ended 31 March 2006 from the Tanzania Revenue Authority ("TRA") demanding US$433,000 for unremitted import duties on gas distribution pipeline and other related equipment and US$373,000 for uninvoiced and unremitted Value Added Tax. The Company has objected to the demands and claims exemptions under the terms of the Songo Songo PSA and Customs Tariff Act. As such, no accrual has been made in these financial statements.

Post Balance Sheet Events

The Company's rights regarding the seven licences adjoining the Songo Songo field ("Adjoining Blocks") were for the period until October 2005. The Ministry of Energy and Minerals ("MEM") agreed to extend this period to 11 January 2006. The Company was required to incur a minimum of US$2.0 million in October 2001 terms adjusted for the change in the US Industrial Producer Price Index on seismic and other exploration work since October 2001 and commit to drill one well on the Adjoining Blocks before 11 January 2006.

The Company acquired 377 kilometers of 2D seismic on the Adjoining Blocks during October 2005. The MEM indicated that provided the Company committed to drill a well by 30 April 2006 and drilled it by 11 April 2007, it may retain the Adjoining Blocks. On 24 May 2006, the Company informed MEM that it did not intend to drill a well on the Adjoining Blocks and that it has relinquished the acreage to concentrate on the higher prospectivity of Songo Songo West. The relinquishment of this acreage has no impact on the rights under the PSA to the Discovery Blocks and hence the potential of the existing field and the Songo Songo West prospect.

Off-Balance Sheet Transactions

As at 31 March 2006, the Company had no off-balance sheet arrangements.

Operating Leases

The Company has entered into a five year rental agreement that expires on 30 November 2007 for the use of the offices in Dar es Salaam at a cost of approximately US$102,000 per annum.

Related Party Transactions

There have been no transactions undertaken with related parties during the quarter ended 31 March 2006.

Summary Quarterly Results

The following is a summary of the results for the Company for the most recently completed quarters:

	2006	2005				2004	
Financial (US$'000 *except where otherwise stated*)	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Revenue	**2,073**	2,741	2,156	512	350	391	50
Profit/(loss) after taxation	**83**	396	785	(275)	(518)	(643)	(34)
Netback (US$/mcf)	**2.05**	2.27	1.68	3.86	3.24	3.00	3.51
Working capital	**2,118**	2,211	3,559	2,789	4,895	1,216	2,289
Shareholders' equity	**16,928**	16,662	16,096	15,240	15,444	11,516	11,857
Profit/(loss) per share – basic	**–**	0.02	0.03	(0.01)	(0.02)	(0.03)	(0.03)
Profit/(loss) per share – diluted	**–**	0.02	0.03	(0.01)	(0.02)	(0.03)	(0.04)
CAPITAL EXPENDITURE							
Geological and geophysical	**514**	2,001	148	520	88	137	10
Pipeline and infrastructure	**305**	868	110	902	210	479	1
Power development	**–**	34	224	531	–	–	–
Other equipment & business development	**32**	(1)	3	5	5	150	148
OPERATING							
Additional Gas sold (mmscf)							
industrial	**229.8**	299.3	260.7	119.7	96.9	107.1	13.5
power	**682.2**	766.1	905.4	–	–	–	–
Average price per mcf (US$)							
industrial	**7.63**	7.86	7.26	6.19	5.23	5.31	5.41
power	**1.79**	2.15	1.24	–	–	–	–

Operating Hazards and Uninsured Risks

The business of EastCoast is subject to all of the operating risks normally associated with the exploration for, and the production, storage, transportation and marketing of oil and gas. These risks include blowouts, explosions, fire, gaseous leaks, migration of harmful substances and oil spills, any of which could cause personal injury, result in damage to, or destruction of, oil and gas wells or formations or production facilities and other property, equipment and the environment, as well as interrupt operations. In addition, all of EastCoast's operations will be subject to the risks normally incident to drilling of natural gas wells and the operation and development of gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blowouts, equipment failures and other accidents, sour gas releases, uncontrollable flows of oil, natural gas or well fluids, adverse weather conditions, pollution and other environmental risks. Drilling conducted by EastCoast overseas will involve increased drilling risks of high pressures and mechanical difficulties, including stuck pipe, collapsed casing and separated cable. The impact that any of these risks may have upon EastCoast is increased due to the fact that EastCoast currently only has one producing property. EastCoast will maintain insurance against some, but not all, potential risks; however, there can be no assurance that such insurance will be adequate to cover any losses or exposure for liability. The occurrence of a significant unfavourable event not fully covered by insurance could have a material adverse effect on EastCoast's financial condition, results of operations and cash flows. Furthermore, EastCoast cannot predict whether insurance will continue to be available at a reasonable cost or at all.

Foreign Operations

All of EastCoast's operations and related assets are located in countries which may be considered to be politically and/or economically unstable. Exploration or development activities in such countries may require protracted negotiations with host governments, national oil companies and third parties and are frequently subject to economic and political considerations, such as, the risks of war, actions by terrorist or insurgent groups, expropriation, nationalization, renegotiation or nullification of existing contracts, taxation policies, foreign exchange restrictions, changing political conditions, international monetary fluctuations, currency controls and foreign governmental regulations that favour or require the awarding of drilling contracts to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. In addition, if a dispute arises with foreign operations, EastCoast may be subject to the exclusive jurisdiction of foreign courts.

In the foreign countries in which EastCoast will conduct business, currently limited to Tanzania, the state generally retains ownership of the minerals and consequently retains control of (and in many cases, participates in) the exploration and production of hydrocarbon reserves. Accordingly, these operations may be materially affected by host governments through royalty payments, export taxes and regulations, surcharges, value added taxes, production bonuses and other charges.

All of EastCoast's development properties and all of its proved natural gas reserves are located offshore on the Songo Songo Island in Tanzania, and, consequently, EastCoast's assets will be subject to regulation and control by the government of Tanzania and certain of its national and parastatal organizations. EastCoast and its predecessors have operated in Tanzania for a number of years and believe that it has good relations with the current Tanzanian government. However, there can be no assurance that present or future administrations or governmental regulations in Tanzania will not materially adversely affect the operations or future cash flows of EastCoast.

Additional Financing

Depending on future exploration, development, and marketing plans, EastCoast may require additional financing. The ability of EastCoast to arrange such financing in the future will depend in part upon the prevailing capital market conditions as well as the business performance of EastCoast. There can be no assurance that EastCoast will be successful in its efforts to arrange additional financing on terms satisfactory to EastCoast. If additional financing is raised by the issuance of shares from treasury of EastCoast, control of EastCoast may change and shareholders may suffer additional dilution.

From time to time EastCoast may enter into transactions to acquire assets or the shares of other companies. These transactions may be financed partially or wholly with debt, which may temporarily increase EastCoast's debt levels above industry standards.

Industry Conditions

The oil and gas industry is intensely competitive and EastCoast competes with other companies which possess greater technical and financial resources. Many of these competitors not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum, natural gas products and other products on an international basis. Oil and gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and invasion of water into producing formations. Currently, EastCoast's Songo Songo natural gas property is operated by EastCoast. There is a risk that in the future either the operatorship could change and the property operated by third parties or operations may be subject to control by national oil companies, Songas, or parastatal organisations and, as a result, EastCoast may have limited control over the nature and timing of exploration and development of such properties or the manner in which operations are conducted on such properties.

The marketability and price of natural gas which may be acquired, discovered or marketed by EastCoast will be affected by numerous factors beyond its control. There is currently no developed natural gas market in Tanzania and no infrastructure with which to serve potential new markets beyond that being constructed by EastCoast and Songas. The ability of EastCoast to market any natural gas from current or future reserves may depend upon its ability to develop natural gas markets in Tanzania and the surrounding region, obtain access to the necessary infrastructure to deliver sales gas volumes, including acquiring capacity on pipelines which deliver natural gas to commercial markets. EastCoast is also subject to market fluctuations in the prices of oil and natural gas, uncertainties related to the delivery and proximity of its reserves to pipelines and processing facilities and extensive government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and gas and many other aspects of the oil and gas business. EastCoast is also subject to a variety of waste disposal, pollution control and similar environmental laws.

The oil and natural gas industry is subject to varying environmental regulations in each of the jurisdictions in which EastCoast may operate. Environmental regulations place restrictions and prohibitions on emissions of various substances produced concurrently and oil and natural gas and can impact on the selection of drilling sites and facility locations, potentially resulting in increased capital expenditures.

Additional Gas

EastCoast has the right, under the terms of the PSA, to market volumes of Additional Gas subject to satisfying the requirements to deliver Protected Gas to Songas.

There is a risk that Songas could interfere in EastCoast's ability to produce, transport and sell volumes of Additional Gas if EastCoast's obligations to Songas under the Gas Agreement are not met. In particular, Songas has the right to request reasonable security on all Additional Gas sales.

Under the terms of the contracts with Kioo Limited, Tanzania Breweries Limited and Karibu Textile Mills Ltd., the Company is liable to pay penalties in the event that there is a shortfall in the Additional Gas supply in excess of 5% of the contracted quantity. The penalties equate to the difference between the price of gas and an alternative feedstock multiplied by the notional daily quantities. The maximum penalty for shortfall gas is a total of US$1.1 million for these three contracts and the remedy is payable as a credit against future monthly invoices.

Replacement of Reserves

EastCoast's natural gas reserves and production and, therefore, its cash flows and earnings are highly dependent upon EastCoast developing and increasing its current reserve base and discovering or acquiring additional reserves. Without the addition of reserves through exploration, acquisition or development activities, EastCoast's reserves and production will decline over time as reserves are depleted. To the extent that cash flow from operations is insufficient and external sources of capital become limited or unavailable, EastCoast's ability to make the necessary capital investments to maintain and expand its oil and natural gas reserves will be impaired. There can be no assurance that EastCoast will be able to find and develop or acquire additional reserves to replace production at commercially feasible costs.

Asset Concentration

EastCoast's natural gas reserves are limited to one property, the Songo Songo field, and the production potential from this field is limited to five wells. There has been limited production from the five wells in the Songo Songo field to date. There is no assurance that EastCoast will have sufficient deliverability through the existing wells to provide additional natural gas sales volumes, and that there may be significant capital expenditures associated with any remedial work or new drilling required to achieve deliverability. In addition, any difficulties relating to the operation or performance of the field would have a material adverse effect on EastCoast.

Environmental and Other Regulations

Extensive national, state, and local environmental laws and regulations in foreign jurisdictions will affect nearly all of EastCoast's operations. These laws and regulations set various standards regulating certain aspects of health and environmental quality, provide for penalties and other liabilities for the violation of such standards and establish in certain circumstances obligations to remediate current and former facilities and locations where operations are or were conducted. In addition, special provisions may be appropriate or required in environmentally sensitive areas of operation. There can be no assurance that EastCoast will not incur substantial financial obligations in connection with environmental compliance. Significant liability could be imposed on EastCoast for damages, cleanup costs or penalties in the event of certain discharges into the environment, environmental damage caused by previous owners of property purchased by EastCoast or non-compliance with environmental laws or regulations. Such liability could have a material adverse effect on EastCoast. Moreover, EastCoast cannot predict what environmental legislation or regulations will be enacted in the future or how existing or future laws or regulations will be administered or enforced. Compliance with more stringent laws or regulations, or more vigorous enforcement policies of any regulatory authority, could in the future require material expenditures by EastCoast for the installation and operation of systems and equipment for remedial measures, any or all of which may have a material adverse effect on EastCoast. As party to various licenses, EastCoast has an obligation to restore producing fields to a condition acceptable to the authorities at the end of their commercial lives.

While management believes that EastCoast is currently in compliance with environmental laws and regulations applicable to EastCoast's operations in Tanzania, no assurances can be given that EastCoast will be able to continue to comply with such environmental laws and regulations without incurring substantial costs.

EastCoast's petroleum and natural gas operations are subject to extensive governmental legislation and regulation and increased public awareness concerning environmental protection.

No provision has been recognised for future decommissioning costs which are anticipated to be immaterial as it is forecast that there will still be commercial gas reserves once EastCoast relinquishes the licence in 2026. EastCoast expects that the cost of complying with environmental legislation and regulations will increase in the future. Compliance with existing environmental legislation and regulations has not had a material effect on capital expenditures, earnings or competitive position of EastCoast to date. Although management believes that EastCoast's operations and facilities are in material compliance with such laws and regulations, future changes in these laws, regulations or interpretations thereof or the nature of its operations may require the Company to make significant additional capital expenditures to ensure compliance in the future.

Volatility of Oil and Gas Prices and Markets

EastCoast's financial condition, operating results and future growth will be dependent on the prevailing prices for its natural gas production. Historically, the markets for oil and natural gas have been volatile and such markets are likely to continue to be volatile in the future. Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes to the demand for oil and natural gas, whether the result of uncertainty or a variety of additional factors beyond the control of EastCoast. Any substantial decline in the prices of oil and natural gas could have a material adverse effect on EastCoast and the level of its natural gas reserves. Additionally, the economics of producing from some wells may change as a result of lower prices, which could result in a suspension of production by EastCoast.

No assurance can be given that oil and natural gas prices will be sustained at levels which will enable EastCoast to operate profitably. From time to time EastCoast may avail itself of forward sales or other forms of hedging activities with a view to mitigating its exposure to the risk of price volatility.

The Songo Songo field is the first gas field to be developed in East Africa. The Company has therefore been able to negotiate industrial gas sales contracts with gas prices that are at a discount to the lowest cost alternative fuels in Dar es Salaam, namely HFO.

Recently, there has been increased activity in the exploration of oil and gas in Tanzania, with the result that one well has been drilled on an adjacent prospect to Songo Songo. There has been a commercial gas discovery in the south of Tanzania at Mnazi Bay and a number of Production Sharing Agreements are being negotiated for the drilling onshore and offshore Tanzania. These developments will be closely monitored by the Company, but could lead to increased competition for gas markets and lower gas prices in the future.

In addition, various factors, including the availability and capacity of oil and gas gathering systems and pipelines, the effect of foreign regulation of production and transportation, general economic conditions, changes in supply due to drilling by other producers and changes in demand may adversely affect EastCoast's ability to market its gas production. Any significant decline in the price of oil or gas would adversely affect EastCoast's revenues, operating income, cash flows and borrowing capacity and may require a reduction in the carrying value of EastCoast's gas properties and its planned level of capital expenditures.

Uncertainties in Estimating Reserves and Future Net Cash Flows

There are numerous uncertainties inherent in estimating quantities of proved and probable reserves and cash flows to be derived therefrom, including many factors beyond the control of EastCoast. The reserve and cash flow information contained herein represents estimates only. The reserves and estimated future net cash flow from EastCoast's properties have been independently evaluated by McDaniel & Associates Consultants Ltd. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, crude oil price differentials to benchmarks, future prices of oil and natural gas, operating costs, transportation costs, cost recovery provisions and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date of the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of EastCoast. Actual production and cash flows derived therefrom will vary from these evaluations, and such variations could be material.

Title to Properties

Although title reviews have been done and will continue to be done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of EastCoast which could result in a reduction of the revenue received by EastCoast.

Acquisition Risks

EastCoast intends to acquire natural gas infrastructure and possibly additional oil and gas properties. Although EastCoast performs a review of the acquired properties that it believes is consistent with industry practices, such reviews are inherently incomplete. It generally is not feasible to review in depth every individual property involved in each acquisition. Ordinarily, EastCoast will focus its due diligence efforts on the higher valued properties and will sample the remainder. However, even an in depth review of all properties and records may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Inspections may not be performed on every well, and structural or environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. EastCoast may be required to assume pre-closing liabilities, including environmental liabilities, and may acquire interests in properties on an “as is” basis. There can be no assurance that EastCoast's acquisitions will be successful.

Reliance on Key Personnel

EastCoast is highly dependent upon its executive officers and key personnel. The unexpected loss of the services of any of these individuals could have a detrimental effect on EastCoast. EastCoast does not maintain key life insurance on any of its employees.

Controlling Shareholder

W David Lyons, the Company’s non-executive Chairman, is the sole controlling shareholder of EastCoast and holds approximately 99.3% of the outstanding Class A shares and approximately 16.7% of the Class B shares before the exercise of his options. Consequently, Mr. Lyons holds approximately 22.9% of the equity and controls 67.9% of the total votes of EastCoast.

Financial Statements

Consolidated Income Statement (unaudited)

(thousands of US dollars except per share amounts)	Note	Three months ended 31 Mar 2006	31 Dec 2005	31 Mar 2005
Revenue		**2,073**	2,741	350
Cost of sales				
Production and distribution expenses		**(165)**	(320)	(36)
Depletion expense		**(324)**	(375)	(29)
Gross profit		**1,584**	2,046	285
Other income		**16**	10	6
Administrative expenses		**(1,293)**	(1,190)	(785)
Foreign exchange losses		**(41)**	(2)	(24)
Profit/(loss) before taxation		**266**	864	(518)
Taxation	I	**(183)**	(468)	–
Profit/(loss) after taxation		**83**	396	(518)
Profit/(loss) per share				
Basic and diluted (US$)		**–**	0.02	(0.02)

See accompanying notes to the interim consolidated financial statements.

Consolidated Balance Sheet (unaudited)

(thousands of US dollars)	Note	As at 31 March 2006	As at 31 December 2005
ASSETS			
Current assets			
Cash and cash equivalents		**3,454**	3,198
Trade and other receivables		**2,044**	2,862
		5,498	6,060
Natural gas properties and other equipment	2	**15,537**	15,037
		21,035	21,097
LIABILITIES			
Current liabilities			
Trade and other payables		**3,380**	3,849
Non current liabilities			
Deferred tax		**619**	506
Deferred Additional Profits Tax		**108**	80
SHAREHOLDERS' EQUITY			
Capital stock	3	**16,324**	16,237
Capital reserve		**860**	764
Accumulated loss		**(256)**	(339)
		16,928	16,662
		21,035	21,097

See accompanying notes to the interim consolidated financial statements.

Consolidated Statement of Cash Flows (unaudited)

	Three months ended		
(thousands of US dollars)	31 Mar 2006	31 Dec 2005	31 Mar 2005
CASH FLOWS FROM OPERATING ACTIVITIES			
Profit/(loss) after taxation	**83**	396	(518)
Adjustments for:			
Depletion and depreciation	**351**	402	54
Stock-based compensation	**96**	170	71
Deferred taxation	**113**	506	–
Deferred Additional Profits Tax	**28**	80	–
Funds from operations before working capital changes	**671**	1,554	(393)
(Increase)/decrease in trade and other receivables	**818**	(245)	(54)
Increase/(decrease) in trade and other payables	**(576)**	336	(93)
Net cash flows from operating activities	**913**	1,645	(540)
CASH FLOWS USED IN INVESTING ACTIVITIES			
Acquisition of natural gas properties and other equipment	**(851)**	(2,902)	(303)
Increase/(decrease) in trade and other payables	**107**	(30)	
Net cash used in investing activities	**(744)**	(2,932)	(303)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net proceeds from rights issue	**–**	–	4,365
Proceeds from exercise of options	**87**	–	10
Net cash flow from financing activities	**87**	–	4,375
Increase/(decrease) in cash and cash equivalents	**256**	(1,287)	3,532
Cash and cash equivalents at the beginning of the period	**3,198**	4,485	2,040
Cash and cash equivalents at the end of the period	**3,454**	3,198	5,572

See accompanying notes to the interim consolidated financial statements.

Statement of Changes in Shareholders' Equity
(Unaudited)

(thousands of US dollars)	Capital stock	Capital reserve	Accumulated Loss	Total
Note	3			
Balance as at 31 December 2004	11,862	381	(727)	**11,516**
Rights issue net of share issue costs	4,365	–	–	**4,365**
Options exercised	10	–	–	**10**
Profit for the year	–	–	388	**388**
Stock-based compensation	–	383	–	**383**
Balance as at 31 December 2005	16,237	764	(339)	**16,662**
Options exercised	87	–	–	**87**
Profit for the period	–	–	83	**83**
Stock based compensation	–	96	–	**96**
Balance as at 31 March 2006	**16,324**	**860**	**(256)**	**16,928**

See accompanying notes to the interim consolidated financial statements.

Notes to the Consolidated Interim Financial Statements

(Unaudited)

Basis of preparation

The interim consolidated financial statements are measured and presented in US dollars as the main operating cash flows are linked to this currency through the commodity price.

The same accounting policies and methods of computation have been followed as the consolidated financial statements at 31 December 2005. The interim consolidated financial statements for the three months ended 31 March 2006 should be read in conjunction with the audited financial statements and related notes for the year ended 31 December 2005.

Management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenue and expenses during the period. Actual results could differ from these estimates.

Statement of Compliance

These interim consolidated financial statements of EastCoast Energy Corporation ("EastCoast" or the "Company") including comparatives, have been prepared in accordance with IAS 34 of the International Financial Reporting Standards ("IFRS") and interpretations issued by the Standing Interpretations Committee of the IASB.

These principles differ in certain respects from those in Canada. These differences are described in note 7.

1 Tax

As at 31 March 2006, there were temporary differences between the carrying value of the assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Accordingly a deferred tax liability has been recognised for the quarter ended 31 March 2006.

Tax rate reconciliation:

	Three months ended		
US$000	**31 March 2006**	31 December 2005	31 March 2005
Profit/(loss) before taxation	**266**	864	(518)
Provision for income tax calculated at the statutory rate of 30%	**80**	259	(155)
Add/(deduct) the tax effect of non-deductible income tax items:			
Other income	**(5)**	(6)	(1)
Administrative and operating expenses	**53**	80	33
Stock based compensation	**29**	51	21
Other	**26**	84	102
	183	468	–
The tax charge may be analysed as follows:			
Current tax	**70**	59	–
Deferred tax	**113**	409	–
	183	468	–

The deferred income tax liability includes the following timing differences:

Differences between tax base and carrying value of natural gas properties	**575**	474	–
Other timing differences	**44**	32	–
	619	506	–

2 Natural gas properties and other equipment

US$000	Natural gas properties	Leasehold improvements	Computer equipment	Vehicles	Fixtures & fittings	Total
Costs						
As at 1 January 2006	15,693	156	59	38	37	**15,983**
Additions	819	-	4	27	1	**851**
As at 31 March 2006	16,512	156	63	65	38	**16,834**
Depletion/Depreciation						
As at 1 January 2006	853	49	19	13	12	**946**
Charge for the period	324	13	5	5	4	**351**
As at 31 March 2006	1,177	62	24	18	16	**1,297**
Net Book Values						
At 31 March 2006	**15,335**	**94**	**39**	**47**	**22**	**15,537**
At 31 December 2005	14,840	107	40	25	25	**15,037**

Included in the Natural Gas Properties as at 31 March 2006, is US$0.5 million representing the costs of acquiring and processing 328 kilometers of seismic on the Nyuni 'A' area subject to the farm-in terms with a subsidiary of Aminex plc. This asset will not be depleted until it is determined whether or not proved reserves are attributable to the properties, or impairment occurs.

In determining the depletion charge, it is estimated by the independent reserve engineers that future development costs of US$69.6 million will be required to bring the total proved reserves to production.

3 Capital stock

Thousands of shares or US$	Authorised	Issued	Valuation
Class A shares			
As at 31 December 2005 and 31 March 2006	50,000	1,751	983
Class B shares			
As at 31 December 2005	50,000	21,513	15,254
Options exercised	–	100	87
As at 31 March 2006	**50,000**	**21,613**	**15,341**
Total Class A and B shares as at 31 March 2006	**100,000**	**23,364**	**16,324**

In Q1 2006, 100,000 options were exercised at a price of Cdn$1 per option. A total of 1,887,400 options remain outstanding. These options have a term of 10 years and an exercise price of Cdn$1.

4 Contingent liabilities

The Company received two letters in the period ended 31 March 2006 from the Tanzania Revenue Authority ("TRA") demanding US$433,000 for unremitted import duties on gas distribution pipeline and other related equipment and US$373,000 for uninvoiced and unremitted Value Added Tax. The Company has objected to the demands and claims exemptions under the terms of the Songo Songo PSA and Customs Tariff Act. As such, no accrual has been made in these financial statements.

5 Contractual obligations

Under the terms of the PSA, in the event that there is a shortfall in Protected Gas as a consequence of the sale of Additional Gas, the Company is liable to pay the difference between the price of Protected Gas (US$0.55/mmbtu) and the price of an alternative feedstock multiplied by the volumes of Protected Gas up to a maximum of the volume of Additional Gas sold. Songas has the right to request reasonable security on all Additional Gas sales. No security has been requested for the initial industrial gas sales but Songas has this right and may require security for larger volumes.

Songas has confirmed that, subject to certain conditions, security will not be required for the supply of Additional Gas to the Ubungo Power Plant, for the supply of up to 15 mmscf/d for a period of five years for additional power generation and up to 10 mmscf/d for the industrial sector.

The Company has requested clarification of Songas's intention with respect to security for the additional 245 MWs of new generation that TANESCO intends to install in Dar es Salaam during 2006/2007.

On 21 September 2005, the Company signed an agreement with a subsidiary of Aminex plc to farm-in to 382 square kilometers ("Area A") of the Nyuni Production Sharing Agreement ("Nyuni PSA") that lies adjacent to the Songo Songo field. During October, the Company fulfilled the initial terms of the farm-in agreement by acquiring in excess of 300 kilometers of seismic in Area A. Under the terms of the agreement, the Company has until 30 September 2006 to elect whether or not to participate in the drilling of a well on Area A. If the Company elects to drill, it will pay either 42% to earn a 35% interest in Area A or 64% to earn a 50% interest. TPDC has indicated that it may not be possible to split out Area A from the remainder of the Nyuni PSA. Accordingly, the Company is in discussion with Aminex plc with respect to transferring the work undertaken on Area A into an equitable interest in the Nyuni PSA.

Under the terms of the contracts with Kioo Ltd., Tanzania Breweries Ltd. and Karibu Textile Mills Ltd., the Company is liable to pay penalties in the event that there is a shortfall in the Additional Gas supply in excess of 5% of the contracted quantity The penalties equate to the difference between the price of gas and an alternative feedstock multiplied by the notional daily quantities. The maximum penalty for shortfall gas is a total of US$1.1 million for these three contracts and the remedy is payable as a credit against future monthly invoices.

6 Post Balance Sheet Events

The Company's rights regarding the seven licences adjoining the Songo Songo field ("Adjoining Blocks") were for the period until October 2005. The Ministry of Energy and Minerals ("MEM") agreed to extend this period to 11 January 2006. The Company was required to incur a minimum of US$2.0 million in October 2001 terms adjusted for the change in the US Industrial Producer Price Index on seismic and other exploration work since October 2001 and commit to drill one well on the Adjoining Blocks before 11 January 2006.

The Company acquired 377 kilometers of 2D seismic on the Adjoining Blocks during October 2005. The MEM indicated that provided the Company committed to drill a well by 30 April 2006 and drilled it by 11 April 2007, it may retain the Adjoining Blocks. On 24 May 2006, the Company informed MEM that it did not intend to drill a well on the Adjoining Blocks and that it has relinquished the acreage to concentrate on the higher prospectivity of Songo Songo West. The relinquishment of this acreage has no impact on the rights under the PSA to the Discovery Blocks and hence the potential of the existing field and the Songo Songo West prospect.

7 Reconciliation of IFRS to Accounting Principles Generally Accepted in Canada

These interim consolidated financial statements have been prepared in accordance with the IFRS basis of accounting, which differ in some respects from those in Canada.

This reconciliation has been restated for the recognition of a difference between IFRS and Canadian Generally Accepted Accounting Principles ("GAAP"). On 31 August 2004, the Company was spun off from PanOcean Energy Corporation pursuant to a scheme of arrangement. IFRS does not permit the setting up of a deferred tax liability for all taxable temporary differences arising from the initial recognition of an asset or liability except in a business combination. Under Canadian GAAP, a deferred tax liability has to be recognised for the taxable temporary differences arising from the initial recognition of an asset or liability under any scenario.

The following are the differences in accounting principles:

	31 March 2006		31 December 2005	
US$000	IAS	CDN	IAS	CDN
Current assets	5,498	5,498	6,060	6,060
Natural gas properties and other equipment	15,537	17,313	15,037	16,852
	21,035	**22,811**	**21,097**	**22,912**
Current liabilities	3,380	3,380	3,849	3,849
Non-current liabilities	727	2,487	586	2,385
Capital stock	16,324	16,324	16,237	16,237
Reserves	604	620	425	441
	21,035	**22,811**	**21,097**	**22,912**

The adjustment has no material impact on the profit and loss account for the three months ended 31 March 2006 and the year ended 31 December 2005.

There are no other material differences in accounting principles as they pertain to the accompanying consolidated financial statements.

Forward Looking Statements

This disclosure contains certain forward-looking estimates that involve substantial known and unknown risks and uncertainties, certain of which are beyond EastCoast's control, including the impact of general economic conditions in the areas in which EastCoast operates, civil unrest, industry conditions, changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced, increased competition, the lack of availability of qualified personnel or management, fluctuations in commodity prices, foreign exchange or interest rates, stock market volatility and obtaining required approvals of regulatory authorities. In addition there are risks and uncertainties associated with oil and gas operations, therefore EastCoast's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking estimates and, accordingly, no assurances can be given that any of the events anticipated by the forward-looking estimates will transpire or occur, or if any of them do so, what benefits, including the amounts of proceeds, that EastCoast will derive therefrom.

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