MANAGEMENT'S DISCUSSION AND ANALYSIS

FORWARD LOOKING STATEMENTS

THIS MDA OF FINANCIAL CONDITIONS AND RESULTS OF OPERATIONS SHOULD BE READ IN CONJUCTION WITH THE COMPANY'S UNAUDITED INTERIM FINANCIAL STATEMENTS FOR THE NINE MONTHS ENDED 30 SEPTEMBER 2005, AND THE AUDITED FINANCIAL STATEMENTS AND MDA FOR THE PERIOD ENDED 31 DECEMBER 2004. THIS MDA IS BASED ON THE INFORMATION AVAILABLE ON NOVEMBER 25, 2005. 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 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 FOR ONE THOUSAND STANDARD CUBIC FEET OF ADDITIONAL GAS. 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") only operating 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 kilometers spur to the Wazo Hill Cement Plant.

Songas utilises the Protected Gas (maximum 44.8 mmscf/d) as feedstock for its gas turbine electricity generators at Ubungo, for onward sale to the Wazo Hill Cement Plant and for some limited electrification for 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 is the operator of the natural gas development and 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 is obliged to fund work in return for their rights to explore for and sell Additional Gas. The Company's right regarding the Adjoining Blocks is for the period from October 2001 to October 2005. This period was extended to 11 January 2006 at the request of TPDC to Ministry of Energy and Minerals ("MEM"). During this period, the Company must 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 by October 2006, demonstrate to MEM compliance with submitted Additional Gas plans and make diligent attempts to sell Additional Gas. If the MEM determines that the Company has failed to comply with these obligations, the Company's rights to the Adjoining Blocks ceases.

(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).

(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 per 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 a rateable share of the Profit Gas.

(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 $3.5 million. The World Bank agreed to finance this increase and accordingly the pipeline capacity was increased from circa 65 mmscf/d to 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 increases to 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

EastCoast Energy was spun off from PanOcean Energy Corporation ("PanOcean") on 31 August 2004. Accordingly, results prior to this date were consolidated within PanOcean.

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

Q3 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:

(US$'000 except production and per mcf data)	**Three months ended 30 Sept 2005**	**Three months ended 30 June 2005**	**Nine months ended 30 Sept 2005**
Gross sales volume (mcf):			
Industrial sector	260,730	119,682	477,332
Power sector	905,423	-	905,423
Total volumes	*1,166,153*	*119,682*	*1,382,755*
Average sales price (US$/mcf):			
Industrial sector	7.26	6.19	6.58
Power sector	1.24	-	1.24
Average price	*2.58*	*6.19*	*3.08*
Gross sales revenue	3,013	741	4,261
Gross tariff for processing plant and pipeline infrastructure	480	111	667
Gross net revenue after tariff	**2,533**	**630**	**3,594**
Analysed as to:			
Company Cost Recovery	1,898	473	2,694
Company Profit Gas	161	39	227
Company operating revenue (see Note 1)	**2,059**	**512**	**2,921**
TPDC Profit Gas	474	118	673
	2,533	**630**	**3,594**
Operating costs for Additional Gas:			
Ring main distribution pipeline	55	35	113
Share of well maintenance	19	4	26
Other operating costs	16	11	36
Depletion	376	37	443

Note 1

The Company's total revenues for the quarter amounted to US$2,156,000 after uplifting the Company's operating revenue of US$2,059,000 by US$97,000 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.

Volumes

Industrial

During the quarter, sales volumes increased by 118% with the commencement of Additional Gas sales to Tanzania-China Friendship Textile Limited at approximately 0.6 mmscf/d and a full quarter consumption by Karibu Textile Mills Ltd. who commenced gas consumption at the end of Q2.

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. Between the commencement of UGT 6 on 8 June and 30 September, 905 mmscf was consumed at an average of 7.9 mmscf/d.

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$7.26/mcf (Q2 2005: US$6.19/mcf) during Q3. The average price for nine months to 30 September 2005 was US$6.58/mcf.

The gas price achieved for the industrial sector will fluctuate with world oil prices and the discount agreed with the customers. The price of HFO in Dar es Salaam in any particular month is estimated to be reflective of HFO prices in Dubai some two to three months prior to delivery, plus transportation costs. The monthly range of Additional Gas price sold to industrial customers in Dar es Salaam in the nine months to 30 September 2005 was US$4.56/mcf in January to US$ 7.51/mcf in September.

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 Complex, from the minimum of US$0.67/mbtu (US$0.62/mcf) to the maximum of US$2.32 mbtu (US$2.13/mcf). Prior to 21 July, there was severe disruption at the Ubungo power plant caused by major failures of both UGT 1 and UGT 3. UGT 3 was removed to Canada for repairs and recommenced electricity generation on 21 July. UGT 1 had its blades repaired on site and came back in mid-October. As a result of these turbine failures, TANESCO has had to generate electricity at the IPTL power plant utilising expensive heavy fuel oil as its feedstock. Accordingly, the price of US$0.67/mmbtu was used for Additional Gas supplied from 8 June 2005 to 31 July 2005. August and September was charged at US$1.96/mmbtu.

Consumers currently pay approximately 8.5 cents/kwh for their electricity. This electricity price is comparable with other electricity tariffs in East Africa, but is significantly lower than the current prices achieved in western economies. This puts some downward pressure on the price that gas can be sold to the power sector in the longer term.

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, 74 cents/mcf ("Ringmain Tariff") has been deducted from the achieved sales price of US$7.26/mcf (Q2 2005: US$6.19/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.

Operating Costs

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$210,000 (Q2 2005: US$96,000) and US$19,000 (Q2 2005: US$4,200) was allocated for the Additional Gas.

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

Netbacks

The netback per mcf before general and administrative costs and overheads may be analysed as follows:

	Three months ended		**Nine months ended**
(Amounts in US$/mcf)	**30 Sept 2005**	**30 June 2005**	**30 Sept 2005**
Gas price - industrial	7.26	6.19	6.58
Gas price - power	1.24	-	1.24
Average price for gas	2.58	6.19	3.08
Tariff (after allowance for the Ringmain Tariff)	(0.41)	(0.93)	(0.48)
TPDC Profit Gas	(0.41)	(0.99)	(0.49)
Net selling price	**1.76**	**4.27**	**2.11**
Well maintenance and other operating costs	(0.03)	(0.12)	(0.04)
Ringmain distribution pipeline costs	(0.05)	(0.29)	(0.08)
Netback	**1.68**	**3.86**	**1.99**

Netbacks were lower in Q3 against Q2 due to overall lower average prices as a result of power sector sales at lower prices than industrial sales. However, the higher volumes have reduced the well maintenance and distribution pipeline costs per mcf.

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:

	Three months ended		**Nine months ended**
(Figures in US$'000)	**30 Sept 2005**	**30 June 2005**	**30 Sept 2005**
Employee costs	272	188	647
Stock based compensation	71	71	214
Travel & accommodation	33	35	124
Communications	14	21	52
Office	113	86	283
Consultants	162	66	369
Insurance	57	45	144
Auditing & taxation	13	15	46
Depreciation	23	19	66
Reporting, regulatory and corporate finance	71	87	238
Other corporate	39	48	135
Directors' fees	17	15	47

Total general and administrative expenses	**885**	**696**	**2,365**

G&A averaged approximately US$0.29 million per month (including the stock-based compensation and depreciation) during the period (Q2 2005: US$0.23 million). The increase in G&A primarily resulted from an increase in the bonus accruals and a lower capitalization of the consultants costs. In Q2, consultants spent more time in negotiating a gas sales contract to Ubungo Complex and the related costs were capitalised. The cost per gross mcf sold fell significantly during the quarter to US$0.75/mcf from US$5.81/mcf in Q2 due to commencement of sales to power sector and the increase in sales volumes to industrial customers. The G&A per mcf is expected to fall with an increase in contracted 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. A third of the options vested on the grant date and accordingly a third of the fair value of the options was expensed in 2004 along with a monthly charge of US$24,000 representing the amortization of the remaining fair value of the options over the vesting period. This monthly 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, but this is paid by TPDC through the profit sharing arrangements. On receipt of any Profit Gas under the PSA, the Company's revenue will be grossed up by the income tax due.

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. As at 30 September 2005, there were un-recovered costs of US$9.8 million and therefore no APT is payable.

Management does not anticipate that any income tax or APT will be payable in 2005 as the forecast revenues will not be sufficient to cover the un-recovered costs brought forward and the expenditures incurred in 2005. The actual taxes paid will be 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.

The Company has utilised a previously unbooked deferred tax asset to offset against a deferred tax expense arising in the quarter for timing differences. As at 30 September 2005 there were no material temporary differences between the carrying value of the assets and liabilities for financial reporting purposes and the amounts used for taxation purposes.

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 2004, the proven reserves as evaluated by the independent reservoir engineers, McDaniel & Associates Consultants Ltd. ("McDaniels") were 171.2 bcf on a life of licence basis. This leads to a depletion charge of US$0.31/mcf in Q3 2005 (Q2 2005: US$0.30/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 30 September 2005, the Company had US$9.8 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$1.3 million in the period to 30 Sept 2005. The components of the Company's cash flow were as follows:

(Figures in US$'000)	Three months ended 30 Sept 2005	Three months ended 30 June 2005	Nine months ended 30 Sept 2005
Profit/(loss) for the period	785	(275)	(8)
Adjustment for non cash items	470	127	722
Pre tax cash flows from operations	**1,255**	**(148)**	**714**
Working capital adjustments	(661)	910	102
Natural gas properties and other equipment expenditure	(485)	(1,958)	(2,746)
Net proceeds from rights issue and exercise of options	-	-	4,375
Net increase/(decrease) in cash and cash equivalent	**109**	**(1,196)**	**2,445**

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$0.5 million in Q3 2005 (Q2 2005: US$2 million). The capital expenditure may be analysed as follows:

(Figures in US$'000)	Three months ended 30 Sept 2005	Three months ended 30 June 2005	Nine months ended 30 Sept 2005
Geological and geophysical	148	520	757
Pipelines and infrastructure	110	903	1,220
Power development	224	531	755
Other equipment	3	4	14
	485	**1,958**	**2,746**

The Company continued to prepare the seismic programme in Q3 2005. The seismic work commenced in October 2005 after it was postponed due to unfavourable weather conditions that prevented the seismic vessel getting to Tanzania. As at 30 September, the Company had paid for the initial cost of mobilising the vessel of US$0.3 million and had opened an irrevocable letter of credit of US$1.0 million in favour of the seismic contractor. Costs relating to preparatory work have been capitalised. The total cost of the seismic programme, including project management, processing and interpretation, is estimated at US$2.1 million for the acquisition of 589 kilometers of seismic on the Songo Songo licence area and US$0.5 million for the acquisition of 328 kilometers on the farm-in licence acreage.

Limited pipeline development was undertaken in Q3 compared to Q2 when the extension to Karibu Textile Mills Limited was constructed.

Power development includes the costs of installing meters and the negotiation of contracts for the supply of gas to the Ubungo Power Plant that is owned and operated by Songas Limited. After extensive negotiations in Q2, the contract was finalized during Q3 and signed on 1 October 2005.

Working Capital

Working capital as at 30 September 2005 was US$3.6 million (30 June 2005: US$2.8 million) and may be analysed as follows:

(Figures in US$'000)	**30 Sept 2005**	**30 June 2005**	**31 Dec 2004**
Cash and cash equivalents	4,485	4,376	2,040
Trade and other receivables	2,617	658	441
	7,102	**5,034**	**2,481**
Total current liabilities	3,543	2,245	1,265
Working capital	**3,559**	**2,789**	**1,216**

Included in 'cash and cash equivalents' is US$1.0 million held as cash cover for an irrevocable letter of credit in favour of the seismic contractor. The letter of credit was utilised in full in Q4 2005.

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 30 September 2005, US$473,000 (30 June 2005: US$117,000) 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 30 September 2005, US$263,000 (30 June 2005: US$38,000) 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 30 September 2005 the Company owed Songas US$402,000 (30 June 2005: US$81,000) for the tariff.

Also included in cash and cash equivalents was US$100,000 advanced by Tanzania China Friendship Textile Co Ltd. as a deposit for their connection. This amount has been repaid to the company subsequent to the period end after they had consumed in excess of US$200,000 of Additional Gas. This amount is shown in current liabilities.

The majority of the cash is held in US and Cdn dollars in Mauritius and 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 30 September 2005, US$1,182,000 was due for the month of August and September (including VAT). The amount has been subsequently received. Trade and other receivables also include an amount of US$1,344,000 (including VAT) due from Songas Limited for the supply of Additional Gas to Ubungo Complex. US$380,000 was received in November and the remainder is forecast to be received in early December.

The current liabilities increased in Q3 primarily as a result of the increase in the amount of profit share due to TPDC at the quarter end resulting from the increase in Additional Gas sales. Current liabilities also included an accrual of US$961,000 for the pipeline construction to Karibu Textile Mills Limited which was completed and capitalised in Q2, but still payable at the end of Q3.

Management forecasts that the Company will be able to meet its remaining 2005 capital expenditure programme in Q4 of US$2.0 - US$2.5 million (primarily seismic and pipeline connections) through the use of existing funds and self - generated cash flows forecast for the next three months. In addition, the Company has no bank borrowings and there is scope for utilising debt funding once the longer term contract for the supply of gas to the Ubungo power plant (resulting from the addition of UGT6), is in place.

Outstanding Share Capital

There were 23.3 million shares outstanding at 30 September 2005 and may be analysed as follows:

No of shares (‘000)	**30 Sept 2005**	**30 June 2005**	**31 Dec 2004**
Shares outstanding			
Class A shares	1,751	1,751	1,751
Class B shares	21,513	21,513	19,386
	23,264	23,264	21,137
Convertible securities:			
Options	1,987	1,987	2,000
Fully diluted Class A and Class B shares	**25,251**	**25,251**	**23,137**
Weighted average			
Class A and Class B shares	23,264	23,264	21,137
Options	1,987	1,987	2,000
Weighted average diluted Class A and Class B shares	**25,251**	**25,251**	**23,137**

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$1.00 per option. During Q1 12,600 options were exercised at a price of Cdn$1 per option. A total of 1,987,400 options remain outstanding. These options have a term of 10 years and an exercise price of Cdn$1.

Contractual Obligations and Committed Capital Investment

The Company’s rights regarding the seven licences adjoining the Songo Songo field (“Adjoining Blocks”) are for the period until October 2005. The Ministry of Energy and Minerals (“MEM”) agreed to extend this period to 11

January 2006 following a request by TPDC after the seismic vessel was prevented from getting to Tanzania due to unfavourable weather conditions that threatened the safety of the operation. If the Company wishes to retain the Adjoining Blocks, it must by 11 January 2006, incur a minimum of US$2.0 million (in October 2001 terms) on seismic and commit to drill one well on the Adjoining Blocks before October 2006.

Management approved the seismic programme and signed a contract with Silver Queen Maritime Limited in Q2. US$2.6 million has been committed for the overall seismic programme (US$2.1 million on the Songo Songo licence area and US$0.6 million on the Nyuni Production Sharing Arrangement farm-in) of which US$0.6 million has already been incurred and US$1.0 million was held as cash cover under an irrevocable letter of credit as at 30 September 2005. Silver Queen Maritime Limited commenced and completed the seismic work in October 2005 and currently the data is being processed and interpreted. A decision as to drill a well in 2006 will be taken once the results of the seismic work have been analysed.

Management has signed a contract for the construction of a 3.6 kilometer pipeline spur to two new customers, Lakhani Industries Limited Textile and Murzah Oil Mills Limited. This pipeline is currently in the process of being constructed and should be complete by the end of Q1 2006 at a cost of US$0.9 million.

On September 21, 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 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 on Area A. Under the terms of an Agreement that Aminex plc has with Petrom S.A, Petrom S.A. has 30 days from the receipt of the seismic that has been run on Area A to acquire a 30% interest in the Nyuni PSA. The Company now has until 30 September 2006 to elect whether or not to participate in the drilling of a well on Area A. If Petrom S.A. acquires a 30% interest then the Company will incur 42% of the costs of drilling the well (pre-completion) for a 35% interest in the PSA. If Petrom S.A does not elect to acquire a 30% interest, then the Company will incur 64% of the cost of drilling the well (pre-completion) for a 50% interest in the PSA.

Management expects to fund its committed capital investments from existing and self generated funds in Q4.

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.

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. No security has been requested for the initial industrial gas sales but Songas still retains this right and may require security for larger volumes.

Off-Balance Sheet Transactions

As at 30 September 2005, 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$92,000 per annum.

Related Party Transactions

The Company was spun off from PanOcean through a Scheme of Arrangement on 31 August 2004. W. David Lyons is the Chairman and controlling shareholder of both PanOcean and EastCoast. The Company has entered into an arms length agreement with PanOcean for the use of certain administrative and technical support services provided by PanOcean staff for the transitional period after the spin off. These services were not utilised in the nine month period to 30 September 2005.

There have been no other transactions undertaken with related parties during the period.

SUMMARY QUARTERLY RESULTS

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

	2005			2004	
	Q3	**Q2**	**Q1**	**Q4**	**Q3**
Financial (US$'000 except where otherwise stated)					
Revenue	**2,156**	512	350	391	50
Profit/(loss) for the period	**785**	(275)	(518)	(642)	(34)
Netback (US$/mcf)	**1.68**	3.86	3.24	3.00	3.51
Working Capital	**3,559**	2,789	4,895	1,216	2,289
Shareholders' Equity	**16,096**	15,240	15,444	11,516	11,857
Profit/(loss) per share – basic	**0.03**	(0.01)	(0.022)	(0.30)	(0.036)
Profit/(loss) per share – diluted	**0.03**	(0.01)	(0.022)	(0.30)	(0.036)
Capital expenditure					
Geological and geophysical	**148**	520	88	137	10
Pipeline and infrastructure	**110**	902	210	479	1
Power development	**224**	531	-	-	-
Other equipment & business development	**3**	5	5	150	148
Operating					
Additional Gas sold (mmscf) - Industrial	**260.7**	119.7	96.9	107.1	13.5
Additional Gas sold (mmscf) - Power	**905.4**	-	-	-	-
Average price per mcf (US$) - Industrial	**7.26**	6.19	5.23	5.31	5.41
Average price per mcf (US$) - Power	**1.24**	-	-	-	-

The Company was spun out from PanOcean Energy Corporation and commenced operations on 31 August, 2004. Results for Q3 2004 are for the month ended 30 September 2004.