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EastCoast Energy announces results to 31 December 2004 and reports a 101% increase in the gross proven recoverable natural gas reserves in Tanzania

TORTOLA, British Virgin Islands. EastCoast Energy Corporation ("EastCoast Energy" or the "Company") announces its results for the period 31 August 2004 to 31 December 2004.

	Period ended December 2004
Financial (US$'000)	
Revenue	441
Loss for the period	(727)
Working Capital	1,216
Shareholders' Equity	11,516
Outstanding Shares ('000s)	
Class A shares	1,751
Class B shares	19,386
Options	2,000
Natural Gas Reserves (based on McDaniel & Associates Consultants Ltd. reserves report as at 31 December 2004)	
Gross Recoverable Reserves to end of licence (bcf)	
Proved	171.2
Probable	84.2
Proved plus probable	255.4
Present Value, discounted at 10% (US$ million)	
Proved	35.5
Proved plus probable	43.4

There are no comparative numbers as the Company was consolidated within PanOcean Energy Corporation until 31 August 2004.

2004 Highlights

- EastCoast successfully commissioned the five natural gas wells at Songo Songo with a forecast maximum field deliverability of 158 million cubic feet per day.
- Produced (as the contract field operator) 4.6 billion cubic feet of natural gas from the Songo Songo field from the commencement of commercial operations to year end 2004.
- Increased the gross certified proved recoverable gas reserves available to be marketed by EastCoast by 101% to 171.2 billion cubic feet over the licence period.
- Completed a pressure reduction station and a 14-kilometre ring main distribution pipeline at Dar es Salaam to provide connections for EastCoast to sell "Additional Gas" production to industrial customers in the area.
- Commenced natural gas sales to Dar es Salaam industries, Kioo Limited and Tanzanian Breweries Limited who purchased 120.6 million cubic feet (an average of 1.2 million cubic feet per day) to 31 December 2004.
- Signed five additional industrial gas sales contracts. These are expected to be connected over the first half of 2005 tripling our Company's industrial gas sales to 3.5 million cubic feet per day by Q3 2005.
- Commenced negotiations with TANESCO, the electricity utility, to supply gas to a 34 MW turbine that is expected to be operational by Q3 2005 and have a maximum utilization of 8.4 million cubic feet per day.
- Prepared a 500 kilometre seismic acquisition programme over the Songo Songo field and adjacent licence blocks.
- Prepared and announced a Rights Issue that successfully raised gross proceeds of Cdn$5.5 million in Q1 2005.

2005 Outlook

Over 2005, EastCoast will:

- Expand the gas sales to industrial and utility customers to increase the revenues EastCoast earns from the distribution and sale of Additional Gas.
- Closely monitor the Songo Songo wells and pressure data to increase our understanding of the field, and its production and reserve potential.
- Assess drilling leads on leases adjacent to Songo Songo to identify potential prospects to be targeted in 2006.
- Seek to secure further opportunities in East Africa and elsewhere.

OPERATIONAL REVIEW

Background

The Company's operations at the Songo Songo gas field in Tanzania provide for EastCoast to operate five producing wells and two 35 mmscf/d dehydration and refrigeration gas processing units on Songo Songo Island. Gas processed by EastCoast is then transported to Dar es Salaam through a 25-kilometre 12-inch offshore pipeline and a 207-kilometre 16-inch onshore pipeline.

Gas produced and sold from the Songo Songo field is classified as either Protected Gas or Additional Gas. The Protected Gas is 100% owned by the Tanzanian Petroleum Development Corporation ("TPDC") and is sold to Songas Limited ("Songas") under a 20 year Gas Agreement either for use at the Ubungo Power Plant or for onward sale to the Wazo Hill Cement Plant or for the Village Electrification Programme. At a 100% utilisation rate, the Protected Gas consumption is forecast to be 44.8 mmscf/d and therefore the total Protected Gas required over the twenty year period of TPDC's gas agreement with Songas cannot be more than 327 bcf.

For the purposes of calculating the level of gas available for the Additional Gas it has been assumed that the Protected Gas users will operate their facilities at a 75% utilisation rate over a twenty year period reflecting maintenance downtime and times of non usage. This assumption will be reviewed on an annual basis based on historic and projected usage.

The Protected Gas users and their forecast demand are as follows:

Protected Gas consumer	**Theoretical max 100% load factor** (mmscf/d)	**Most likely** (mmscf/d)
Ubungo		
Two ABB turbines	10.97	8.23
Two GE turbines	18.55	13.91
Fifth GE turbine	8.40	6.30
	37.92	**28.44**
Wazo Hill Cement Plant		
Kiln 1	3.40	2.55
Kiln 2	2.47	1.85
	5.87	**4.40**
Village Electrification Programme	1.00	0.75
Total daily gas demand	**44.79**	**33.59**
Reserves over 20 years from commercial start up (bcf)	**327.0**	**245.2**

Production

Commercial production commenced from the Songo Songo field on 20 July 2004 when the Ubungo Power Plant was commissioned.

By the end of December 2004, 4.6 bcf of Protected Gas and Additional Gas had been produced from the field since commercial start up as follows:

Gas produced mmscf	**Total**
Protected & Additional Gas Production	**4,623**
Analysed between:	
Protected Gas sales	4,097
Additional Gas sales	121
Flare and generator consumption at the gas processing plant	325
Line pack	80
	4,623

Protected Gas Sales

In the period to 31 December, 2004 the Protected Gas consumers' utilisation rate was 55% and may be analysed as follows:

	Period 20 July 2004 – 31 December 2004		
	Protected Gas consumed		**Utilisation rate**
	mmscf	**mmscf/d**	**%**
Protected Gas user			
Ubungo	3,696.9	22.09	58
Wazo Hill Cement Plant	399.7	2.41	41
Village Electrification Programme	-	-	n/a
Total consumption	**4,096.6**	**24.50**	**55**
Total consumption at 100% utilisation	7,300.7	**44.79**	**n/a**
Protected Gas not utilised	**3,204.2**	**n/a**	**n/a**

The Protected Gas utilisation rate was relatively low in 2004 as:

1. The two ABB turbines were not operational at Ubungo until October 2004. The four turbines consumed an average of 22.1 mmscf/d from commercial start up to 31 December 2004. This increased to an average of 27.3 mmscf/d in December when all four turbines were operational. The fifth turbine was commissioned in March 2005 and has a forecast maximum consumption of 8.4 mmscf/d.
2. The two kilns at the Wazo Hill cement plant were not operating at expected capacity until January 2005. The plant consumed an average of 2.4 mmscf/d from commercial start up and peaked at 3.0 mmscf/d in November when both kilns were being utilised.
3. The scheme to supply gas for electrification for some of the villages affected by the development of the Songo Songo project is unlikely to be implemented until Q3 2005.

As a consequence of the above, 3.2 bcf of gas was not utilised by the Protected Gas consumers and consequently the maximum gas required for the Protected Gas users over the 20 year term of their gas agreement fell to 323.8 bcf as at 31 December 2004. This shortfall allows the Additional Gas reserves to be raised by a similar amount.

Additional Gas Sales

Small volumes of Additional Gas sales commenced in September 2004. This is discussed under ‘Infrastructure and Markets’ below.

Flare and generator

After normal and expected flaring during the commissioning and start up of the gas processing plant, there was a malfunction of a pressure control valve installed by the contractor and this led to the flaring of slightly higher than normal volumes of gas. The problem was fixed in January 2005 and the flaring has returned to normal levels.

Line Pack

It is estimated that the 232 Kilometre pipeline to Dar es Salaam is capable of holding a maximum of 85 mmscf of gas. This is reflected in the amount of July production that was required to fill the line prior to gas sales.

Well capacity testing

With these initial production rates, the Company has performed a series of pressure tests using Keller well head gauges and bottom-hole gauges that were installed in all the wells (except SS-9) before the start up of the field. These were pulled in November and data was analysed to provide a more accurate determination of reserves. New bottom-hole gauges were installed in the wells (two in SS-5 and SS-7 and one in SS-3 and SS-4) and these will be pulled in May 2005.

As at 31 December, tests had been performed on four of the wells namely the two onshore wells, SS-3 and SS-4, and two offshore well SS-7 and SS-5. In December, SS-9 was brought on stream after the Company successfully pulled the back pressure valve that had been stuck in the tubing hanger. This enabled the Company to run a perforated tubing plug to prevent any operational problems with two sets of gauges and a length of wireline that were left downhole at the time of the 1997 extended well program. This well was then tested in January 2005.

The results of the well tests during the period, based on the requirement to have 1,600 psig of pressure in the gas processing plant, are as follows:

Mmscf/d	**Well flow rates** 1997 capacity forecast	**31 December 2004 capacity forecast**
Capacity		
SS-3	10	17
SS-4	10	19
SS-5	60	65
SS-7	20	22
SS-9 (Note 1)	40	35
	140	**158**
Maximum Protected Gas demand	(45)	(45)
Available for Additional Gas	**95**	**113**

Note 1: The well test on SS-9 was conducted in January 2005. Potentially the well will produce at rates in excess of 35 mmscf/d, but rates will be restricted to ensure that no downhole problems occur from gauges and wireline left in the hole in 1997

The capacity of the wells was 13% higher than forecast at the time of the 1997 well tests.

This means that:

- There is a potential of 113 mmscf/d of production capacity for Additional Gas above the peak demand for the Protected Gas; and
- Even if the two largest wells are unable to produce, the Company can still supply the Protected Gas users at peak demand and 13 mmscf/d of Additional Gas for a short period of time.

SS-9 was tested in January 2005 and the well was produced at a rate of 35 mmscf/d. Accordingly, the perforated tubing plug and the downhole gauges and wireline do not seem to be having a significant effect on the production rate. The test indicated that the well could produce at rates in excess of 35 mmscf/d. However, the well will be produced conservatively given its downhole condition and the fact that there is excess production capacity.

Reservoir interference tests have been conducted to understand the main connectivity between the main reservoir area surrounding SS-5 and SS-9 and the southern area of SS-7. The initial conclusions are that the connectivity in the reservoir is good and that SS-7 is communicating with other wells in the field.

The areas that the Company will focus on in 2005 are:

- Understanding the aquifer strength of the reservoir; and
- The connectivity of the wells and fault transmissibility.

Seismic programme

There are nine licences included in the Company's PSA with TPDC, namely the two blocks within which the Songo Songo field lies ("Discovery Blocks") and seven blocks in adjacent areas ("Adjoining Blocks").

The PSA obligates the Company to perform certain work on the Adjoining Blocks including US$2.0 million (in October 2001 terms) of seismic and related work before October 2005 and drill a well by October 2006, if it wishes to retain the Adjoining Blocks for the term of the PSA. During 2004, TPDC agreed that this seismic obligation would be satisfied even if some of the seismic was run over the Discovery Blocks. In the event that EastCoast elects not to explore or retain the Adjoining Blocks, there is no exploration obligation for seismic acquisition or drilling in 2005 or 2006.

The seismic used to evaluate the field was acquired between 1978 and 1984 and is considered fair for its vintage.

In 2005, the Company intends to:

- Reprocess 450 kilometres of the existing seismic;
- Acquire and process approximately 10 kilometres of infill 2D seismic in order to delineate the field; and
- Acquire and process approximately 490 kilometres of 2D seismic over some exploration acreage within both the Discovery Blocks and the Adjoining Blocks.

The field is located within a shallow operating environment where the water is sometimes less than 10 meters in depth. Accordingly the seismic will be conducted with a shallow marine vessel.

It is intended to complete all the processing of the data by the end of 2005.

Reserves

In accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities, the independent petroleum engineers, McDaniel & Associates Consultants Ltd ("McDaniel") prepared a report dated 11 April 2005 that assessed the EastCoast natural gas reserves based on information on the Songo Songo field as at 31 December 2004 (the "McDaniel Report").

The reserves summary to the end of the license period (October 2026) for the Additional Gas was as follows:

BCF	**Gross Reserves 2004**	**Net Reserves 2004**
Certified Reserves		
Proved producing	124.6	66.2
Proved non producing	46.6	35.6
Total proved ("1P")	**171.2**	**101.8**
Probable	84.2	39.3
Proven and probable ("2P")	**255.4**	**141.1**

Gross reserves are based on 100% of the property gross Additional Gas reserves (excluding Protected Gas).
Net reserves are based on the Company's share of the Cost Gas and Profit Gas revenues (see Management's Discussion & Analysis for definitions).

During the course of the year, there has been a:

- 101% increase in the gross 1P reserves from 85.3 bcf to 171.2 bcf; and
- 2% decrease in the gross 2P reserves from 259.6 bcf to 255.4 bcf.

For the purpose of calculating the gross Additional Gas reserves, McDaniel has assumed that 249.3 bcf will be required to meet the demands of the Protected Gas users from 1 January 2005. This compares with 247.1 bcf at 1 January 2004. 4.7 bcf was consumed during 2004 by the Protected Gas users (including gas required for testing pre-commercial operations).

On a life of field basis the gross recoverable proven and proven and probable reserves increases to 203.1 bcf (net 123.9 bcf) and 358.3 bcf (net 202.8 bcf) respectively. This provides an indication of the recoverable reserves in the field that may be exploited with additional capital expenditure prior to the end of the licence period.

The principal assumptions used by McDaniel in their evaluation of the Tanzanian PSA are as follows:

Year	1P gas sales mmscf/d	2P gas sales mmscf/d	Brent crude US$/BBL	1P US$/mcf	2P US$/mcf	Annual inflation %
2005	4.7	4.7	39.5	3.88	3.96	2.0
2006	12.1	15.7	37.5	2.54	2.75	2.0
2007	20.7	32.9	35.4	2.27	2.51	2.0
2008	32.3	33.8	33.4	2.29	2.52	2.0
2009	32.3	34.0	32.9	2.32	2.56	2.0
2010	32.3	34.0	32.6	2.36	2.60	2.0
2011	32.3	34.0	33.3	2.41	2.65	2.0
2012	32.3	34.0	34.0	2.46	2.71	2.0
2013	32.3	34.0	34.6	2.50	2.76	2.0
2014	32.3	34.0	35.3	2.55	2.81	2.0
2015	32.3	34.0	36.0	2.61	2.87	2.0
2016	16.4	34.0	36.7	2.66	2.93	2.0
2017	16.4	34.0	37.5	2.71	2.99	2.0
2018	16.4	34.0	38.3	2.77	3.05	2.0
2019	16.4	34.0	39.0	2.82	3.11	2.0
2020	16.4	34.0	39.8	2.88	3.17	2.0
2021	16.4	34.0	40.5	2.93	3.23	2.0
2022	16.4	34.0	41.4	2.99	3.30	2.0
2023	16.4	34.0	42.3	3.05	3.36	2.0
2024	16.4	34.0	43.1	3.11	3.43	2.0
Thereafter	16.4	34.0	43.1	3.11	3.43	2.0

Reserves Reconciliation

BCF	Gross Proved	Gross Proved and probable	Net Proved	Net Proved and probable
Reserves at 31 August 2004	85.3	259.6	55.2	155.7
Extensions	-	-	-	-
Improved recovery	-	-	-	-
Technical revisions	86.0	(4.1)	46.7	(14.5)
Discoveries	-	-	-	-
Acquisitions	-	-	-	-
Dispositions	-	-	-	-
Economic factors	-	-	-	-
Production	(0.1)	(0.1)	(0.1)	(0.1)
Reserves at 31 December 2004	**171.2**	**255.4**	**101.8**	**141.1**

There has been no development activity on the Songo Songo field during 2004 and the increase in the proven reserves has arisen from the reinterpretation of subsurface data and the positive pressure and gas production data since commercial operations commenced in July 2004.

It is forecast that the work program that will be undertaken on the field and adjoining acreage in 2005 and 2006 could lead to an increase in the proven and probable reserves.

Present value of reserves

The estimated value of the Songo Songo reserves based on the assumptions on production and pricing, as detailed above, are as follows:

US$ millions		**2004**			**As at 31 August 2004**	
	5%	**10%**	**15%**	**5%**	**10%**	**15%**
Proved producing	32.5	22.3	16.6	-	-	-
Proved undeveloped	19.2	13.2	9.0	17.7	7.6	2.9
Total proved	**51.7**	**35.5**	**25.6**	**17.7**	**7.6**	**2.9**
Probable	12.9	7.9	5.7	73.3	38.8	22.4
Total proved and probable	**64.6**	**43.4**	**31.3**	**91.0**	**46.4**	**25.3**

Certification for project sponsors

EastCoast contracted Gaffney Cline Associates Ltd ("GCA") to prepare a revised certified reserve report as of 1 January 2005 utilising the more recent surface and subsurface data, including that obtained since production commenced in June 2004. The objective of this report is to demonstrate to the Government of Tanzania, TPDC, Songas and the World Bank that there are sufficient Additional Gas reserves to enable other gas-to-electricity projects to go ahead.

This report has not been prepared in accordance with National Instrument 51-101-Standards of Disclosure for Oil and Gas Activities. Its conclusions and findings have no impact on any of the financial information contained within this annual report.

GCA initially prepared a certified report in January 2001 to support the development of the Songo Songo project by the World Bank and other sponsors. This original report certified that there was 297 bcf of proved recoverable reserves and 580 bcf of proven, probable and commercially recoverable reserves in the Songo Songo field. However, this report limited the proven reserves to the volumes contracted to the Protected Gas users.

GCA reported in March 2005 and their analysis was as follows:

Bcf	**Low estimate**	**Most likely**	**High estimate**
Potential Gross Recoverable Gas Volumes	540	649	875

These volumes represent the total recoverable gas in the Songo Songo field and includes both the Protected Gas and Additional Gas reserves.

The 'low estimate', 'most likely' and 'high estimate' are analogous to Proven, Proven and Probable and Possible respectively with the exception that these cases do not make any assumptions about the level of gas sales (either Protected or Additional Gas).

With this level of certified 'low estimate' reserves, there is 220 bcf of Additional Gas reserves available assuming that Songas consume the Protected Gas at a 100% utilisation from 1 January 2005. This equates to 30 mmscf/d and 60 mmscf/d over a twenty and ten year period respectively. The report has been made available to the World Bank and other sponsors and should facilitate the commitment to other gas to electricity projects.

Operatorship

The Company is the operator of the wells and gas processing plant on Songo Songo Island on behalf of the stakeholders including Songas. Operatorship is on a 'no gain/no loss' basis. Two internationally experienced staff manage the site operations on a rotational basis with back up support from the Company's head office personnel in Dar es Salaam. Twenty-six Tanzanian technicians operate and maintain the wells, gathering system and processing plant.

During the period to 31 December 2004, the gas processing facilities had performed in line with management's expectations and there had been no unplanned shutdowns on Songo Songo Island that had impacted the supply of gas to Dar es Salaam.

The December 2004 Asian Tsunami had a negligible impact on the operations. The gas processing plant is located nine meters above sea level. Subsea installations were inspected for damage caused by high currents associated with the Tsunami, and none was found.

Infrastructure and markets

The infrastructure that transports the gas from the field to Dar es Salaam was commissioned in July 2004. The current infrastructure configuration has a capacity of approximately 70 mmscf/d, limited by the two gas processing trains that have a design specification of 35 mmscf/d each. Of this up to 44.8 mmscf/d has to be made available for the Protected Gas users.

A de-bottlenecking review will be conducted in 2005 to see if the capacity of the two gas processing trains could be increased beyond the specified 35 mmscf/d. To date, 42 mmscf/d has been processed through a single train.

The infrastructure can be increased to approximately 105 mmscf/d by the construction of a third train at the gas processing plant on Songo Songo Island. There are provisions in the agreements with Songas to enable EastCoast to finance and install a third train. This would be considered where the Company has to expand the infrastructure capacity to meet the demand for Additional Gas in Dar es Salaam. This may be financed externally in preference to Company funds.

The Company's 14 km ring main distribution system and pressure reduction station was commissioned during September 2004. This system enables gas to be transported from the main Songo Songo pipeline to industrial customers in the Dar es Salaam area. The ring main will have an initial capacity of 10 mmscf/d. However, it is forecast that it will operate at 50% of capacity on an averaged basis.

Industrial Sales

Gas sales commenced with Kioo Limited and Tanzania Breweries Limited in the latter half of September. These two customers are expected to take an average of 1.4 mmscf/d.

The Company has signed four new five year interruptible contracts with customers adjacent to the ring main distribution pipeline namely Bora Industries Ltd, Aluminium Africa Ltd, Tanzania China Friendship Textile Co Ltd and Nida Textile Mills Ltd.

It is forecast that they will consume an additional 1.3 mmscf/d from EastCoast once they have completed the conversion of their boilers to burn natural gas (forecast to be completed during Q1 and Q2 2005). Three of the connections to these customers have been constructed and the fourth is currently under construction.

In addition a contract has been signed with Karibu Textile Mills Ltd which will require the construction of an 8.6 kilometre plastic pipeline at a cost of US$ 1.1 million. It is forecast that this company will consume an average of 0.8 mmscf/d.

In total it is forecast that gas sales to the industrial customers will increase to 2.7 mmscf/d by the end of Q2 2005 and 3.5 mmscf/d by the end of Q3 2005.

Power sales

As at 31 March 2005, Tanzania had approximately 812 MW of installed generation as follows:

Feedstock	**Power Plant**	**Installed capacity MW**
Hydro:	Kidatu	204
	Mtera	80
	Hale	21
	Pangani Falls	68
	Kihansi	180
	Others	8
		561
Gas fired:	Ubungo (units 1-5)	**151**
Other thermal:	Independent Power of Tanzania Limited ("IPTL")	**100**
Total		**812**

The majority of Tanzania's generation is hydro and is therefore very dependent on the level of the rain during its two rainy seasons which run from November to December and March to May. The country has in the last two years had lower than average rainfalls, which has resulted in the actual hydro capacity being significantly less than its theoretical maximum. In addition the Kihansi hydro plant has been operating at less than 50% of the planned capacity due to environmental restrictions.

The lower generation capacity of the hydro plants in 2004 meant that TANESCO had to base load electricity generation at IPTL, which utilises expensive Heavy Fuel Oil as a feedstock. The increase in the generation capacity at Ubungo as a result of the commissioning of the Songo Songo project ensured that there were no severe black outs during 2004, though demand was held back.

TANESCO has stated its intention to balance its generation capacity by utilising the available gas and ensuring that the hydro is operated at lower rates allowing it to build up the water reserves. The gas fired generation is currently all owned by Songas and is fuelled by Protected Gas. Before the year end, Songas ordered a sixth GE turbine (34 MW) for installation at Ubungo, alongside the existing five turbines that are run on Protected Gas. The sixth turbine has already been shipped to Tanzania and is expected to be operational by Q3 2005 utilising Additional Gas. At 100% utilisation, it is forecast that the turbine would utilise 8.4 mmscf/d.

TANESCO has the option to convert IPTL. Work has commenced to assess its technical feasibility and the World Bank has indicated its willingness to finance the conversion. However, whilst the conversion is economically attractive, disputes between the various interested parties in IPTL may hinder or even prevent the conversion work being undertaken.

It is forecast that TANESCO will need to add 50 MW of generation capacity each year from 2007 to meet a 7% growth in demand for electricity. The cheapest generation capacity in the short term would be gas fired, but longer term the Company has to be competitive with other hydro and coal fired projects.

MANAGEMENT'S DISCUSSION AND ANALYSIS

As at 15 April 2005

FORWARD LOOKING STATEMENTS

THE FOLLOWING MANAGEMENT'S DISCUSSION AND ANALYSIS, DATED 15 APRIL 2005, 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.

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 kilometres of pipeline to Dar es Salaam and a 16 kilometres spur to the Wazo Hill Cement Plant.

Songas utilises the Protected Gas (maximum 44.8 mmscf/d) as feedstock for five of 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 gas delivered to Songas, but does operate 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 a specified area 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. 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 the Ministry of Energy and Minerals ("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 when 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 are 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% 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 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

Pursuant to a Scheme of Arrangement which was approved by the shareholders of PanOcean Energy Corporation ("PanOcean") on 9 June 2004, the Company and its Tanzanian assets were spun off from PanOcean on 31 August 2004. Accordingly, the financial results contained herein are for the period 31 August 2004 to 31 December 2004. The results prior to 31 August 2004 are consolidated within PanOcean.

The Consolidated Financial Statements have been prepared in accordance with the International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board ("IASB") and interpretations issued by the Standing Interpretations Committee of the IASB.

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

Scheme of Arrangement and opening Balance Sheet at 31 August 2004

The principal benefits of the Scheme of Arrangement in respect of the Tanzanian operations were to provide EastCoast with:

- Increased access to both debt and equity capital. The internal competition for capital within PanOcean and the different financing requirements for Tanzania had the potential to constrain the future development of the Tanzanian natural gas business.
- The ability to focus on gas exploration and production and the development of downstream infrastructure combined with marketing and gas-to-electricity conversion activity.

The spin off was achieved by the distribution of the two entities that were party to the Songo Songo agreements to a new entity, EastCoast Energy Corporation. As part of the reorganisation, PanOcean agreed to ensure that the Company was adequately capitalised by:

- Financing the construction of the ring main distribution system up to a maximum of US$2.25 million; and
- Contributing minimum working capital of US$2.0 million to the Company less 50% of the legal fees associated with the spin off.

Opening Balance Sheet

The opening balance sheet of EastCoast as at the point of spin off from PanOcean on 31 August 2004 was as follows:

US$'000	As at 31 Aug
Assets	
Cash and cash equivalents	1,997
Trade and other receivables	2,403
	4,400
Natural gas properties and other equipment	9,411
	13,811
Liabilities	
Current liabilities	
Trade and other payables	1,949
Shareholders' Equity	
Capital Stock	11,862
Reserves	-
	11,862
	13,811

As at 31 August, the Company had working capital of $2.4 million, and this may be analysed as follows:

US$'000	As at 31 Aug
Cash and cash equivalents	1,997
Trade and other receivables	
PanOcean Energy Corporation	1,682
Songas Limited	434
Other receivables	287
	2,403
Total current liabilities	
Terasen International	1,417
Songas Limited	247
PanOcean Energy Corporation	132
Accruals	153
	1,949
Total Working Capital	**2,451**

Results for the period 31 August to 31 December 2004

Revenue and operating costs

The sales of Additional Gas commenced on 18 September 2004. Under the terms of the PSA with TPDC, EastCoast is responsible for invoicing, collecting and allocating the revenue.

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 to 31 December 2004 and accordingly was allocated 81.25% of the Net Revenues in the period as follows:

Period ended (US$'000 except production and per mcf data)	**31 Dec**
Gross sales volume (mcf)	120,593
Average sales price (US$/mcf)	5.31
Gross sales revenue	640
Gross tariff for processing plant and pipeline infrastructure	97
Gross net revenue after tariff	**543**
Analysed as to:	
Company Cost Recovery	407
Company Profit Gas	34
	441
TPDC Profit Gas	102
	543
Operating costs for Additional Gas:	
Ring main distribution pipeline	36
Share of gas production costs	19
Other operating costs	23
Depletion	35

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, 74 cents/mcf ("Ringmain Tariff") has been deducted from the achieved sales price of US$5.31/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.

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$532,000 and US$19,000 was allocated for the Additional Gas. The well maintenance costs included the costs of pulling the down-hole pressure gauges and the remedial work on SS-9 as discussed in the Operational Review.

Pricing

The price of gas for the period was at a discount to the price of Heavy Fuel Oil ("HFO") in Dar es Salaam. This resulted in average gas prices of $5.31 per mcf over the period.

The gas price achieved 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.

It is anticipated that a significant discount will be required to secure gas sales to the power sector. The average price for electricity in Tanzania is approximately 8.5 cents/kwh. This electricity price is comparable with other electricity tariffs in East Africa, but is significantly lower than the current prices achieved in western economies. The Company will be under pressure to keep gas prices at a level that enables TANESCO to be profitable.

Netbacks

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

Period ended (US$/mcf)	**31 Dec**
Average price for gas	5.31
Tariff (after allowance for the Ringmain Tariff)	(0.80)
TPDC profit share	(0.85)
Net selling price	**3.66**
Well maintenance	(0.35)
Ringmain distribution costs	(0.30)
Net Back	**3.01**

Netbacks are currently high as all the sales in 2004 were to the industrial sector at prices that were below the cost of HFO in Dar es Salaam and the Company was recovering 75% of the Net Revenues as Cost Gas. The Netback per mcf is likely to fall if the Company secures gas sales for electricity generation.

General and Administrative Expenses

All general and administrative expenses ("G&A"), with the exception of stock-based compensation, were capitalised until commercial production of Additional Gas commenced on 18 September 2004. The G&A for the period may be analysed as follows:

Period ended (US$'000)	**31 Dec**
Employee costs	216
Stock based compensation	381
Travel & accommodation	45
Communications	24
Office	75
Consultants	175
Insurance	72
Auditing & taxation	34
Other corporate	119
	1,141
Capitalised pre-operating costs	(87)
Total general and administrative expenses	**1,054**

G&A is averaging approximately US$0.25 million per month (including the stock-based compensation). The cost per gross mcf sold was high at US$8.74/mcf. This will fall significantly when contracted sales increase as a large proportion of the G&A is relatively fixed in nature.

Taxes

Under the terms of the PSA, the Company is liable to Tanzanian income tax, but this is paid through the profit sharing arrangements with TPDC. Where income tax is payable the Company's revenue will be grossed up by the tax due and the tax will be shown as a current tax.

The Company has taxable losses brought forward and has incurred losses in the period under review. Therefore the Company was not liable to income tax during 2004.

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 31 December 2004, there were un-recovered costs of $6.6 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 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 2004, the proven reserves as evaluated by the independent reservoir engineers, McDaniel & Associates Consultants Ltd ("McDaniels") increased from 85.3 bcf as at the time of the spin off from PanOcean on 31 August

2004 to 171.5 bcf on a life of licence basis. As a consequence of this and changes in the forecast capital expenditure profile, the depletion charge per mcf decreased to US$0.29/mcf against US$0.44/mcf in Q3 2004.

Recoverable costs

As at 31 December 2004, the Company had US$6.6 million of costs that are recoverable out of 75% of the future Net Revenue.

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.

As at 31 December 2004, McDaniels reviewed the level of the recoverable proven reserves on a life of licence basis and estimated the discounted future net revenues from the production of these proven reserves.

Management has reviewed the current carrying value of the Tanzanian Natural Gas Properties as prepared by McDaniels and has concluded that there should not be a write off of these assets.

Cash flow

Pre tax cash flows from operations decreased by US$0.3 million in the period to 31 December 2004 as there were limited Additional Gas sales to offset the principally fixed cost base. The components of the Company's cash flow were as follows.

Period ended (US$'000)	**31 Dec**
Net loss before taxation	(727)
Adjustment for non cash items	416
Pre tax cash flows from operations	**(311)**
Working capital adjustments	1,278
Acquisition of natural gas properties and other equipment	(924)
Net increase in cash and cash equivalent	**43**

The significant movement in working capital is primarily attributable to the receipt of the majority of the spin off funds due from PanOcean and the retention of revenues from the Additional Gas sales that were paid to TPDC (profit share) and Songas (tariff) shortly after the year end and consequently included in creditors.

Capital Expenditures

Gross capital expenditure amounted to $0.9 million in the period to 31 December 2004. The capital expenditure may be analysed as follows:

Period ended (US$'000)	**31 Dec**
Geological and geophysical	147
Pipelines and infrastructure	480
Business development	297
	924

At the end of 2004, work commenced on preparing for the 2005 seismic program including a re-evaluation of the existing seismic and an analysis of potential exploration leads. Costs associated with this work were capitalised.

The first phase of the construction of the ring main distribution pipeline was completed in September 2004. The ring main connects to the main pipeline at Ubungo (where the Protected Gas feeds into the power plants) and runs to five customers, namely Kioo Limited, Tanzania Breweries Limited, Nida Textiles Ltd, Bora Industries Ltd and Aluminium Africa Ltd. The total cost of the pipeline as at 31 December 2004 was US$2.25 million.

Up to the commencement of gas sales in September, costs associated with the development of the gas market and administrative costs were capitalised. Since September they have been expensed within G&A, with the exception of the year end employee bonus which was partially capitalised to reflect the amount that related to work performed pre the commencement of gas sales.

Working capital

Working capital as at 31 December 2004 was US$1.2 million and may be analysed as follows:

US$'000	**As at 31 Dec**
Cash and cash equivalents	2,040
Trade and other receivables	441
	2,481
Total current liabilities	1,265
Working capital	**1,216**

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 December, US$92,000 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 December, US$251,000 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 December, the Company owed Songas US$97,000 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 will be repaid to the company once they have consumed in excess of US$200,000 of Additional Gas. This amount is also shown in current liabilities.

The majority of the cash is held in US dollars. There are no restrictions in Tanzania for converting Tanzania Schillings 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 December, Kioo Limited and Tanzania Breweries Limited were current in their payments and US$174,000 was due for the month of December (including VAT).

Management forecasts that the Company will be able to meet its 2005 capital expenditure programme of US$5.2 million (primarily seismic and pipeline connections) through the Cdn$5.5 million of gross proceeds from the rights issue and internally generated funds. In addition, the Company has no bank borrowings and there is scope for utilising debt funding once sufficient gas contracts are in place.

Outstanding share capital

There were 21.1 million shares outstanding at 31 December 2004 and may be analysed as follows:

No of shares ('000)	**As at 31Dec**
Shares outstanding	
Class A Shares	1,751
Class B Shares	19,386
	21,137
Convertible securities:	
Options	2,000
Fully diluted Class A and Class B shares	**23,137**
Weighted average	
Class A and Class B Shares	21,137
Options	2,000
Weighted average diluted Class A and Class B Shares	**23,137**

No new Class A or Class B Shares were issued between 31 August and 30 December 2004.

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 year 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. As at the year end, no eligible options had been exercised.

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. If the Company wishes to retain the Adjoining Blocks, it must incur a minimum of US$2.0 million (in October 2001 terms) on seismic pre October 2005 and drill one well on the Adjoining Blocks before October 2006. This has not been shown as a commitment in the accounts as the Company has not yet approved the seismic program and a decision as to drill a well in 2006 will not be taken until the seismic program has been evaluated.

On 19 January 2005 the Board of EastCoast approved the construction of a pipeline to sell gas to Karibu Textile Mills Ltd. The pipeline is to be constructed at a cost of US$1.1 million. This has not been shown as a commitment in the accounts as the Company had not approved the construction before the year end.

Management expects to fund its committed capital investments from the proceeds of the rights issue in March 2005, self generated funds and debt.

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 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 a 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 31 December 2004, the Company had no off-balance sheet arrangements.

Operating leases

The Company has entered into a five year rental agreement for the use of the offices in Dar es Salaam at a cost of approximately $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. As part of the spin off, PanOcean provided the Company with certain working capital and other funding as more fully described under Opening Balance Sheet in this Management Discussion & Analysis.

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 period to 31 December 2004. In addition, the Chief Financial Officer of PanOcean, Robert Wynne, was awarded options in the Company for interim corporate advice.

There have been no other transactions undertaken with related parties during the period ended 31 December 2004.

Post Balance Sheet Events

On 19 January 2005, the Board of EastCoast approved the construction of a pipeline to sell gas to Karibu Textile Mills Ltd. The pipeline is to be constructed at a cost of US$1.1 million.

On 4 March 2005, the Company successfully completed the rights issue through the issue of 2,113,744 Class B shares at a price of Cdn$2.60 per share. This raised Cdn$5.5 million for the Company (Cdn$5.4 million after expenses).

Summary of Quarterly results

EastCoast was a subsidiary of PanOcean until 31 August 2004. Accordingly, the following results are for the period ended 30 September 2004 and the quarter ending 31 December 2004.

US$'000 except where otherwise stated	Period ended 30 September 2004	Q4 2004
Gross Revenue	50	391
Average sales (mmscf/d)	1.1	1.2
Average price (US$/mcf)	5.41	5.31
Loss for the period	(84)	(642)
Operating cash flow before working capital changes	(4)	(307)
Capital expenditure on natural gas properties	158	766
Total assets	13,259	12,781
Loss per share:		
Basic (US$)	0.004	0.030
Diluted (US$)	0.004	0.030

Fourth quarter

The principal developments in Q4 were as follows:

- Average Additional Gas sales increased marginally to 1.2 mmscf/d. In November, Tanzania Breweries Limited reduced its forecast consumption by approx 0.5 mmscf/d as a result of cracks in the boiler tubes on two of its boilers. These boilers are in the process of being replaced and TBL's consumption should increase to 0.7 mmscf/d by June 2005.
- The average price of gas in Q4 was US$ 5.31/mcf against US$5.41 in Q3. The monthly range was US$5.21/mcf to US$5.50/mcf.
- An interruptible conditional contract was signed with Karibu Textile Mills Ltd for the supply of an expected 0.8 mmcf/d of gas in Q3 2005. Shortly after the year end, the Company committed to the construction of a gas pipeline to this customer at a cost of US$1.1 million.
- A pipeline connection to the 100 MW power plant, Independent Power of Tanzania Limited (financed by the World Bank) was completed in Q4. If this plant is converted to gas from HFO it would consume a maximum of 26 mmscf/d at a 100% utilisation rate, though this is uncertain.
- The depletion charge for the quarter decreased from US$0.44/mcf in Q3 to US$0.29/mcf in Q4 primarily as a result of the increase in the proven reserves from 85.3 bcf to 171.5 bcf.
- Capital expenditure increased to US$766,000 with the completion of the initial phase of the ring main distribution system and the commencement of work on the 2005 seismic program.

CONSOLIDATED INCOME STATEMENT

(thousands of US dollars except per share amounts)	**Note**	**Period ended 31 December 2004**
Revenue		
Operating	2	**441**
Cost of sales		
Production and distribution expenses		**(78)**
Depletion		**(35)**
Gross profit		**328**
Other income		**7**
Administrative expenses		**(1,054)**
Other operating expenses	3	**(8)**
Loss before taxation		**(727)**
Taxation	5	**-**
Loss for the period		**(727)**
Loss per share	13	
Basic (US$)		**0.034**
Diluted (US$)		**0.034**

See accompanying notes to the consolidated financial statements.

CONSOLIDATED BALANCE SHEET

(thousands of US dollars)	Note	As at 31 December 2004
Current assets		
Cash and cash equivalents	7	**2,040**
Trade and other receivables	8	**441**
		2,481
Natural gas properties	9	**10,300**
		12,781
LIABILITIES		
Current liabilities		
Trade and other payables	10	**1,265**
SHAREHOLDERS' EQUITY		
Capital stock	12	**11,862**
Capital reserve		**381**
Accumulated loss		**(727)**
		11,516
		12,781

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

(thousands of US dollars)	**Period ended 31 December 2004**
CASH FLOWS FROM OPERATING ACTIVITIES	
Net loss	**(727)**
Adjustments for:	
Depletion	**35**
Stock-based compensation	**381**
Operating loss before working capital changes	**(311)**
Decrease in trade and other receivables	**1,962**
Decrease in trade and other payables	**(684)**
Net cash flow from operating activities	**967**
CASH FLOWS FROM INVESTING ACTIVITIES	
Acquisition of natural gas properties	**(924)**
Net increase in cash and cash equivalents	**43**
Cash and cash equivalents at 31 August 2004	**1,997**
Cash and cash equivalents at 31 December 2004	**2,040**

See accompanying notes to the consolidated financial statements.

STATEMENT OF CHANGES IN EQUITY

(thousands of US dollars)	**Capital stock**	**Capital reserve**	**Accumulated reserve**	**Total**
Balance as at 31 August 2004	11,862	-	-	**11,862**
Loss for the period	-	-	(727)	**(727)**
Stock-based compensation	-	381	-	**381**
Balance as at 31 December 2004	**11,862**	**381**	**(727)**	**11,516**

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

General Information

EastCoast Energy Corporation ("EastCoast" or the "Company") was incorporated on 28 April 2004 under the laws of the British Virgin Islands. Between 28 April 2004 and 30 August 2004, EastCoast was a 100% subsidiary of PanOcean Energy Corporation Limited ("PanOcean"). On 31 August, as part of a Scheme of Arrangement, the Class A and Class B Subordinated Voting Shares of the Company were distributed to the PanOcean shareholders and the Company was listed on the TSX Venture Exchange under the symbols ECE.MV.A and ECE.SV.B. These financial statements are the first audited Consolidated Financial Statements to be prepared by the Company since it was spun out from PanOcean and covers the period 31 August 2004 to 31 December 2004.

The Company is a participant in a gas-to-electricity project in Tanzania. The Company's operations at the Songo Songo gas field in Tanzania include the operation of five producing wells and two 35 mmcf/d dehydration and refrigeration gas processing units on Songo Songo Island on behalf of Songas Limited ("Songas").

Gas produced and sold from the Songo Songo field is classified as either Protected Gas or Additional Gas. Protected Gas is 100% owned by Tanzania Petroleum Development Corporation ("TPDC") and is being sold to Songas under a twenty year Gas Agreement primarily for use at the Ubungo Power Plant and the Wazo Hill cement plant. The Protected Gas can only be used principally as feedstock for specified turbines and kilns.

Gas sales in excess of that required for the Protected Gas users is categorized as Additional Gas. The Company has the exclusive right to explore, develop, produce and market all Additional Gas. Revenues from the sale of Additional Gas, net of transportation tariff, are shared with TPDC in accordance with the terms of the Production Sharing Agreement ("PSA") until October 2026.

Basis of preparation

These 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. 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.

1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

a) Statement of compliance

The Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board ("IASB") and interpretations issued by the Standing Interpretations Committee of the IASB.

In all material respects, these accounting principles are generally accepted in Canada except as described in Note 14.

b) Basis of consolidation

i) Subsidiaries

The Consolidated Financial Statements include the accounts of the Company and all its subsidiaries (collectively, the "Company"). Subsidiaries are those enterprises controlled by the Company. Control exists when the Company has the power, directly or indirectly, to govern the financial or operating policies of those enterprises. The financial statements of subsidiaries are included in the Consolidated Financial Statements from the date that control commences until the date that control ceases.

The following companies have been consolidated within the financial statements:

Subsidiary	Registered	Holding
PAE PanAfrican Energy Corporation	Mauritius	100 percent
PanAfrican Energy Tanzania Limited	Jersey	100 percent

ii) Transactions eliminated upon consolidation

Intra-company balances and transactions, and any unrealised gains arising from intra-company transactions, are eliminated in preparing the Consolidated Financial Statements.

c) Foreign currency

Foreign currency transactions are recorded at the rate of exchange prevailing at the date of the transaction. Monetary assets and liabilities in foreign currencies are translated at period-end rates. Non-monetary items are translated at historic rates, unless such items are carried at market value, in which case they are translated using the exchange rates that existed when the values were determined. Any resulting exchange rate differences are taken to the income statement.

d) Derivative financial instruments

The Company may use derivative financial instruments to hedge its exposure to foreign exchange, interest rate and commodity price risks arising from operational, financing and investment activities. In accordance with its treasury policy, the Company does not hold or issue derivative financial instruments for trading purposes. However, derivatives that do not qualify for hedge accounting are accounted for as trading instruments.

Derivative financial instruments are initially recorded at cost. Subsequent to initial recognition, derivative financial instruments are stated at fair value. Recognition of any resultant gain or loss depends on the hedge accounting model applied.

e) Carried Interest

The Company conducts certain international operations jointly with foreign governments or parastatal entities in accordance with production sharing agreements. Under these agreements, the Company pays both its share and the parastatal's share of operating, administrative and capital costs. The Company recovers all the operating, administrative and capital costs including the parastatal's share of these costs from future revenues over several years. The parastatal's share of operating and administrative costs are recorded in operating and general and administrative costs when incurred and capital costs are recorded in 'Natural Gas Properties'. All recoveries are recorded as revenue in the year of recovery in accordance with accounting policy 1 (m).

f) Natural gas properties

The Company follows the full cost method of accounting for natural gas operations. Capitalised costs include land acquisition, geological and geophysical activities, lease rentals on non-producing properties, drilling both productive and non-productive wells, pipeline and related gas distribution equipment, market development and overhead charges directly related to exploration and development activities.

Costs are depleted on the unit-of-production method based on the estimated proved reserves as estimated by independent reservoir engineers. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion until it is determined whether or not proved reserves are attributable to the properties, or impairment occurs.

Costs incurred are not depleted until commercial production commences. These capitalised costs are periodically assessed to determine whether it is likely that such costs will be recovered in the future. To the extent that there are costs that are unlikely to be recovered in the future, they are written off and charged to earnings.

Capitalised costs, less accumulated depletion are limited to an amount equal to the estimated discounted future net revenue from proven reserves plus the cost (net of impairments) of unproven properties. Proceeds from the sale of natural gas properties are applied against capital costs with no gain or loss recognized, unless the sale would alter the depletion and depreciation rate by 20% or more.

g) Operatorship

The Company operates the gas field, flow lines and gas processing plant on behalf of Songas at cost.

The cost of operating and maintaining the wells and flow lines is paid for by EastCoast and Songas in proportion to the respective volumes of Protected Gas and Additional Gas sales. The costs of operating and maintaining the wells and flow lines are reflected in the accounts to the extent that the costs were incurred to accomplish Additional Gas sales.

The cost of operating the gas processing plant is paid by Songas. Where there are Additional Gas sales, a transportation tariff is paid to Songas as compensation for using the gas processing plant. This transportation tariff is netted off revenue in accordance with accounting policy 1 (m).

h) Trade and other receivables

Trade and other receivables are stated at cost less impairment losses.

i) Cash and cash equivalents

Cash and cash equivalents include cash on deposit and highly liquid investments with original maturities of three months or less.

j) Impairment

Consideration is given on each balance sheet date to determine whether there is any indication of impairment of the carrying value of the Company's assets. If any indication exists, an asset's recoverable amount is estimated. An impairment loss is immediately recognised in the income statement whenever the carrying value of an asset exceeds its estimated recoverable amount. The recoverable amount is the greater of the selling price and value in use. In assessing value in use, the estimated future cash flows are discounted to their present value using a risk adjusted discount factor.

k) Employment benefits

i) Pension

The Company does not operate a pension plan, but it does make defined contributions to the statutory pension fund for employees in Tanzania. Obligations for contributions to the statutory pension fund are recognised as an expense in the income statement as incurred.

ii) Equity and equity-related compensation benefits

The share option plan programme allows Company officers, directors and key personnel to acquire shares at an exercise price determined by the Company. When the options are exercised, equity is increased by the amount of the proceeds received.

The Company accounts for stock based compensation under the rules of IFRS2, Accounting for Share-Based Payments, whereby the fair value of such options is expensed to the income statement in accordance with the specific vesting periods. The fair value of the options is calculated on the grant date using the Black-Scholes option pricing model and the assumptions described in note 12.

iii) Bonuses

Bonuses received by Company senior management are discretionary. Any bonuses specific to exploration and development activities are capitalized against the carrying value of the assets. Other period-end bonuses are recognised in the income statement for the period to which they relate.

l) Provisions

A provision is recognised in the balance sheet when the Company has a legal or constructive obligation as a result of a past event and it is probable that an outflow of economic benefits will be required in the future to settle the obligation. If the effect is material, provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects the current market assessments of the time value of money and, where appropriate, the risks specific to the liability.

No provision has been made for future site restoration costs since the Company has no obligation under the PSA to restore the fields at the end of their commercial lives.

m) Revenue recognition

Revenue represents the Company's share of gas sales during the period, net of the transportation tariff as described in note l (g). The revenue includes those costs that may be recovered under the terms of production sharing agreements including those paid on behalf of parastatal organisations.

n) Operating lease payments

Payments made under operating leases are recognised in the income statement on a straight-line basis over the term of the lease.

o) Taxation

Income tax on the profit for the period comprises current and deferred tax.

The Company is liable to Tanzanian income tax, but this is paid through the profit sharing arrangements with TPDC. Where income tax is payable, the Company's net revenue is grossed up for the tax and the income tax shown as current 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 is payable to the Government of Tanzania.

Deferred tax is provided using the balance sheet liability method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. The amount of deferred tax provided is based on the expected manner of realisation or settlement of carrying amount of assets and liabilities using tax rates substantively enacted at the balance sheet date.

A deferred tax asset is recognised only to the extent that it is probable that future taxable profits will be available against which the assets can be utilised. Deferred tax assets are reduced to the extent that it is no longer probable that the related tax benefits will be realised.

p) Segmental reporting

No segmental information has been presented, since all the revenue generating operations and assets are located in Tanzania.

q) Discontinued operations

A discontinued operation is a clearly distinguishable component of the Company's business that is abandoned or - terminated pursuant to a single plan and, accordingly, the Company only reflects its proportionate interest in such activities.

2 Revenue

	Period ended 31 December 2004
Operating revenue	**441**

The Company started commercial gas sales on 18 September 2004. The revenue reported is the Company's proportionate share of revenue as calculated in accordance with the accounting policy 1(m).

3 Other Operating Expenses

	Period ended 31 December 2004
Foreign exchange loss	**8**

4 Personnel Expenses

The average number of employees during the period was ten. The costs, net of Songas recharges for the operatorship of the gas processing plant, are as follows:

	Period ended 31 December 2004
Wages and salaries	**169**
Social security costs	**25**
Other statutory staff costs	**22**
	216
Capitalised pre-operating costs	**(33)**
	183

Staff costs prior to the commencement of commercial production of Additional Gas on 18 September 2004 have been capitalized.

5 Taxation

The Company is liable for income tax when costs incurred under the Production Sharing Agreement ("PSA") with TPDC have been recovered out of net revenues. Where income tax is payable, the profit available to TPDC is reduced by a corresponding amount. This is reflected in the accounts by grossing up the amount of the Company's net revenue for the income tax and showing the income tax as a current tax.

During the period under review, the Company had not recovered the PSA costs out of Net Revenues and accordingly, the Company was not liable to any Tanzanian income tax. As at 31 December 2004, un-recovered costs on the PSA had accumulated to US$6.6 million.

At December 31, 2004, there are no material temporary differences between the carrying value of the assets and -liabilities for financial reporting purposes and the amounts used for taxation purposes.

6 Opening Balance Sheet

As at 31 August 2004, PanOcean spun out its interests in Tanzania to its shareholders on completion of a Scheme of Arrangement. Accordingly, certain assets and liabilities of PanOcean relating to the Tanzanian business segment were transferred to the Company. The following table analyses the net assets distributed and the opening balance sheet for the Company as at 31 August 2004.

	31 August 2004
Cash and cash equivalents	**1,997**
Trade and other receivables	**2,403**
Natural gas properties and other equipment	**9,411**
Trade and other payables	**(1,949)**
Total net assets	**11,862**

7 Cash and Cash Equivalents

	31 December 2004
Cash and short term deposits	**2,040**

Included in the cash and cash equivalent are:

- US$251,000 advanced from Songas under the terms of the Operatorship Agreement to pay for the costs of operating the wells and gas processing plant.
- US$100,000 advanced from Tanzania-China Friendship Textile Co. Ltd as a deposit for their pipeline connection. This will be repaid once they have consumed in excess of US$200,000 of gas.

8 Trade and Other Receivables due in less than one year

	31 December 2004
Trade receivables	**174**
Prepayments	**84**
Other receivables	**183**
	441

9 Natural Gas Properties

	31 December 2004
Costs	
As at 31 August 2004	**9,411**
Additions	**924**
As at 31 December 2004	**10,335**
Depletion	
As at 31 August 2004	**-**
Charge for the period	**35**
As at 31 December 2004	**35**
Net Book Value	
As at 31 December 2004	**10,300**
As at 31 August 2004	**9,411**

The majority of the Company's costs were capitalised until commercial sale of the Additional Gas commenced on 18 September 2004.

Included in Natural Gas Properties at 31 December 2004 are US$6.3 million of capitalised costs that are recoverable out of 75% of the proceeds of the sale of Additional Gas net of transportation tariffs. The recovery of these costs is dependent on the future sales of commercial gas. The costs are included in Revenue in the period of recovery as set out in note 1 (m) and depleted in accordance with accounting policy 1 (f).

The Company does not have any unproven property costs that are being excluded from the depletion calculation.

10 Trade and Other Payables

	31 December 2004
Trade payables	**308**
Other payables	**957**
	1,265

11 Financial Instruments

The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. The Company monitors these risks. The Company may enter into financial instruments to manage its exposure to these risks.

Credit risk

Substantially all the accounts receivable are due from two customers and Songas. Since the commencement of sale, the Company has not experienced any problem in collecting amounts due from customers. The level of receivables will be closely monitored to minimize any potential default by any of the Company's customers.

Foreign currency risk

The Company's exposure to foreign currency risk is limited to exchange rate fluctuations on foreign currency cash balances and the expenditure in currencies other than the US dollar.

Commodity prices

The Company did not enter into any financial contracts during the period as there was limited exposure to commodity prices.

Fair values

Financial instruments of the Company carried on the balance sheet consist mainly of current assets and current liabilities. Except as noted, there were no significant differences between the carrying value of these financial instruments and their estimated fair value due to their short term to maturity.

12 Capital Stock

Authorised

50,000,000 Class A Common Shares	No par value
50,000,000 Class B Subordinate Voting Shares	No par value

The Class A and Class B shares rank pari passu in respect of dividends and repayment of capital in the event of winding-up. Class A shares carry twenty votes per share and Class B shares carry one vote per share. The Class A shares are convertible at the option of the holder at any time into Class B shares on a one-for-one basis. The Class B shares are convertible into Class A shares on a one-for-one basis in the event that a take over bid is made to purchase Class A shares which must, by reason of a stock exchange or legal requirements, be made to all or substantially all of the holders of Class A shares and which is not concurrently made to holders of Class B shares.

Number of shares (thousands)	**Authorised**	**Issued**	**Valuation at par value**
Class A			
As at 31 August and 31 December	50,000	1,751	983
Class B			
As at 31 August and 31 December	50,000	19,386	10,879
Total as at 31 December	**100,000**	**21,137**	**11,862**

All of the issued capital stock was considered fully paid at the time of spin off from PanOcean.

Stock-based Compensation Plan

On 1 September, 2,000,000 options (‘Options’) were issued to certain Directors, Officers and Consultants. These Options have a term of 10 years and vest as to a third on 1 September 2004 and a third on each of the anniversaries in the following two years. At 31 December 2004, 666,666 options were exercisable. The exercise price for the Options is Cdn$1 representing the closing price of the Class B subordinated Voting Shares on 31 August 2004.

The Company has elected to adopt the fair method value of option valuation IFRS 2. The fair value of each option was estimated as at the date of the grant using the Black-Scholes option pricing model with the following assumptions: risk-free interest rate of 2.6%, dividend yield of 0%, expected life of 10 years and volatility of 60%.

On this basis, the fair value of the Options is US$0.9 million, with a compensation expense of US$381,000 for the period ended 31 December 2004 and a corresponding amount booked to a capital reserve.

No Options were exercised during the period ended 31 December 2004.

13 Loss Per Share

The calculation of basic loss per share is based on the net loss attributable to ordinary shareholders of US$727,000 and a weighted average number of ordinary shares outstanding during the period of 21,137,439.

In computing the diluted earnings per share, 2,000,000 shares were added to the weighted average number of commons shares outstanding during the period ended 31 December, 2004 for the dilutive effect of employee stock options. No adjustments were required to reported earnings from operations in computing diluted per share amounts.

14 Reconciliation of IFRS to Accounting Principles Generally Accepted in Canada

The Consolidated Financial Statements have been prepared in accordance with the IFRS basis of accounting, which differ in some respects from those in Canada.

In Canada, the carrying value of natural gas properties is compared annually to the sum of the undiscounted cash flows expected to result from the company's proved reserves. Should the ceiling test result in an excess of carrying value, the company would then measure the amount of impairment by comparing the carrying amounts of natural gas properties to an amount equal to the estimated net present value of future cash flows from proved plus probable reserves and the lower of cost and market of unproved properties. The Company's risk-free interest rate is used to arrive at the net present value of the future cash flows. To date, application of the Canadian prescribed ceiling test has not resulted in a write-down of capitalized costs.

There were no material differences in accounting principles as they pertain to the accompanying Consolidated Financial Statements.

15 Operating Leases

Non-cancellable operating lease rentals are payable as follows:

	31 December 2004
Less than one year	**92**
Between one and five years	**199**
	291

The Company has rented office property under the five year operating lease expiring 30 November 2007.

16 Post Balance Sheet Events

On 19 January the Board of EastCoast approved the construction of a pipeline to sell gas to Karibu Textile Mills Ltd. The pipeline is to be constructed by Terasen International at a cost of US$1.1 million.

On 4 March 2005, the Company successfully completed the Rights Issue through the issue of 2,113,744 Class B shares at a price of Cdn$ 2.60 per share. This raised Cdn$ 5.5 million for the Company (Cdn$5.4 million after expenses).

17 Commitments and Contingencies

There are no undisclosed commitments as at 31 December 2004.

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 per 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.

18 Directors and Officers Emoluments

USD'000 except no. of share options	Base salary	Bonus	Other compensation	Total	Share
Directors					
W. David Lyons (i) Chairman	4	-	-	**-**	**1,000,000**
Peter R. Clutterbuck (i) Chief Executive Officer	89	-	-	**89**	**400,000**
Nigel A. Friend (i) Vice President and CFO	80	-	-	**80**	**200,000**
John Patterson (i) Non Executive Director	7	-	-	**7**	**50,000**
Robert Spence (i) Non Executive Director	6	-	-	**6**	**50,000**
Officers					
Pierre Raillard (ii) Vice President Operations	29	13	6	**48**	**200,000**

(i) The 'Base Salary' for W.D. Lyons, P.R. Clutterbuck, N. Friend, J. Patterson and R. Spence are in respect of consultancy fees.

(ii) During the period, 50% of the costs of P. Raillard were recharged to Songas for the work undertaken on operating the gas processing plant and maintaining the wells. Accordingly, the emoluments outlined above represent the costs paid directly by the Company.

(iii) 100,000 Options were awarded to a consultant, R Wynne, Chief Financial Officer for PanOcean, for corporate advice.

19 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 period to 31 December 2004.

There have been no other transactions undertaken with related parties during the period ended 31 December 2004.

EastCoast Energy Corporation Limited is a TSXV listed company focused on the production of Tanzanian natural gas and the sale of "Additional Gas" to markets in East Africa. The Company was spun out from PanOcean Energy Corporation and began trading on the TSXV as a separate public company on 31 August 2004 under the trading symbols ECE.SV.B and ECE.MV.A. The company is headquartered in Tortola, British Virgin Islands and maintains its operations offices in Dar es Salaam, Tanzania.

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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