EastCoast Energy

EastCoast Energy Corporation 2005 Annual Report

market builder

Natural gas solutions in East Africa

EastCoast Energy Corporation is a well-financed, international public company engaged in the exploration, development and production of Tanzanian natural gas and the marketing of "Additional Gas" to expanding markets in East Africa.

EastCoast Energy began trading on the TSXV on 31 August 2004 under the trading symbols ECE.SV.B and ECE.MV.A.

The Company maintains its operations offices in Dar es Salaam, Tanzania.

This Annual Report contains certain forward-looking statements based on current expectations, but which involve risks and uncertainties. Actual results may differ materially. See page 40 for additional information on the risks and uncertainties. All financial information is reported in U.S. dollars, unless noted otherwise.

Financial and Operating Highlights

(US$'000 *except where otherwise stated*)	Year ended 31 December 2005	Period ended 31 December 2004	Change
FINANCIAL			
Revenue - industrial	**3,796**	441	761%
Revenue - power	**1,856**	–	–
Total revenue	**5,759**	441	1,206%
Profit/(loss) before taxation	**953**	(727)	231%
Netback (US$/mcf)	**2.11**	3.01	(30%)
Working capital	**2,211**	1,216	82%
Shareholders' equity	**16,662**	11,516	45%
Profit/(loss) per share – basic (US$)	**0.02**	(0.03)	167%
Profit/(loss) per share – diluted (US$)	**0.02**	(0.03)	167%
Cash flow per share – basic (US$)	**0.07**	0.05	40%
Cash flow per share – diluted (US$)	**0.07**	0.04	75%
OUTSTANDING SHARES ('000)			
Class A shares	**1,751**	1,751	–
Class B shares	**21,513**	19,386	11%
Options	**1,987**	2,000	(1%)
OPERATING			
Additional Gas sold (mmscf) - industrial	**777**	121	542%
Additional Gas sold (mmscf) - power	**1,672**	–	–
Average price per mcf (US$) - industrial	**7.07**	5.31	33%
Average price per mcf (US$) - power	**1.66**	–	–
GROSS RECOVERABLE RESERVES TO END OF LICENCE (BCF)			
Proved	241	171	41%
Probable	79	84	(6%)
Proved plus probable	320	255	25%
PRESENT VALUE, DISCOUNTED AT 10% (US$ MILLION)			
Proved	67.7	35.5	91%
Proved plus probable	83.8	43.4	93%

The Company was spun out from PanOcean Energy Corporation and commenced operations on 31 August 2004. The 2004 comparatives are for the four months ended 31 December 2004.

Glossary

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

President & CEO's Letter to Shareholders

Over 2005 EastCoast Energy delivered substantial results in all key performance areas.

- Independent evaluation of Songo Songo reserves increased the gross 2P Songo Songo natural gas reserves to 569 Bcf.
- The proportion of the 2P Songo Songo reserves in which EastCoast has a financial interest increased by 25% to 320 Bcf.
- EastCoast's 2005 2D seismic exploration program, and its reprocessing of earlier 2D seismic, identified a new high potential drilling prospect – approximately 2 kilometers west of the existing Songo Songo field.
- Development of Tanzanian industrial and power markets for natural gas exceeded forecast.
- Net cash flow from operations totalled US$1.8 million.
- A successful 2.1 million share financing was fully subscribed, raising gross proceeds of Cdn$5.5 million.

Reserves increase

The Songo Songo reservoir has proved to be a world class field with excellent deliverability from its five wells. Extensive work was undertaken on the field during 2005 with the reprocessing of 569 kilometers of existing 2D seismic, the acquisition of 212 kilometers of new 2D seismic over the two discovery blocks within which the Songo Songo field lies and the installation and retrieval of sensitive downhole pressure gauges.

The independent reserves engineers, McDaniel & Associates Consultants Ltd, have reviewed all the data and have assessed that the gross proven and probable ("2P") reserves for the total field on a life-of-licence basis increased by 14% to 569 bcf (2004: 498 bcf). The proportion that the Company has a financial interest in under the Songo Songo PSA ("Additional Gas") increased by 25% to 320 bcf (2004: 255 bcf).

To meet the needs of both power and industrial customers in the Dar es Salaam area, EastCoast sales of Additional Gas increased to 11.6 mmscf/d in Q4 2005.

Exploration progress

To respond to the rapid increase in the demand for natural gas by the power and industrial sectors in Dar es Salaam, EastCoast mounted a vigorous exploration program over 2005. Reserves and deliverability need to be ahead of demand so that significant commitments to power and infrastructure developments can be planned with greater certainty.

The most significant exploration result of 2005 is the identification in the Songo Songo West area of a promising prospect approximately 2 kilometers west of the existing Songo Songo field. The Company has reviewed potential drilling targets on Songo Songo West. If gas is discovered, the most likely Gas Initially In Place ("GIIP") is 600 bcf with an upside potential of 1,070 bcf. EastCoast intends to drill at least one well on this location in the next 12 - 18 months – depending on rig availability and financing.

Photo: in Q4, EastCoast shot new seismic on the Songo Songo producing field and adjacent blocks.

To assess the gas potential of the blocks adjoining the Songo Songo field, the Company acquired 377 kilometers of new seismic over seven adjoining blocks ("Adjoining Blocks") during 2005. One lead was identified from the interpretation of this seismic, but it is significantly smaller than Songo Songo West. In the event that the drilling of Songo Songo West is unsuccessful, the risk of drilling this lead increases. The Company is currently evaluating an offer from the Ministry of Energy and Minerals that would require the drilling of a well on this structure by 11 April 2007 in order to retain the Adjoining Blocks.

Work continues on processing and interpreting 328 kilometers of new seismic that was shot on the Nyuni licence acreage subject to the terms of the Nyuni farm-in agreement between EastCoast and a subsidiary of Aminex plc. In the event that further evaluation identifies a commercially viable target, the Company will participate in the drilling of a well on this licence acreage to earn between a 35% and 50% interest in the Nyuni A block. This well has to be drilled by November 2007 and the decision to commit to drill has to be taken by 30 September 2006.

Market development

To meet the needs of both power and industrial customers in the Dar es Salaam area, EastCoast sales of Additional Gas increased to 11.6 mmscf/d in Q4 2005 (industrial sector 3.3 mmscf/d and power sector 8.3 mmscf/d). This demand could increase further over the next two years to in excess of 58 mmscf/d.

The demands of the power sector are a result of the lower than average rainfalls Tanzania has experienced for the last three years and increases in overall demand for electricity. Reduced rainfall has severely impeded TANESCO's ability to run its 561 MW of installed hydro generation capacity at normal levels. The immediate impact has been the imposing of load shedding for up to 14 hours a day. To address this unmet demand, the power utility is looking at several new generation projects.

In February 2006, TANESCO tendered 200 MW of gas-fired generation at Dar es Salaam (100 MW lease plant to be installed by 31 August 2006 and 100 MW of long-term generation to be installed by 31 December 2006). The lease plant is forecast to be operational until the IPTL 100 MW power plant is converted to take gas. This is in addition to a new 45 MW plant that is due to be operational at Tegeta in Dar es Salaam by January 2007. By Q1 2008, the demand from the power sector could reach 61 mmscf/d of Additional Gas (or 43 mmscf/d at a 70% load factor) to fuel the generation of this 245 MW of new capacity.

In addition to power sector growth, management sees the potential to expand sales to the industrial sector. EastCoast's existing industrial customers who benefit from lower energy costs are looking to expand their operations. To meet those needs, the Company is planning to invest approximately US$5.0 million in new distribution infrastructure to add an average of 4.0 mmscf/d of industrial load by the end of 2007.

Infrastructure

To meet this increase in forecast demand, the infrastructure capacity will need to be expanded from its present nameplate capacity of 70 mmscf/d to approximately 120 mmscf/d to accommodate peak loads. The infrastructure may be expanded to 105 mmscf/d – 110 mmscf/d by the addition of a third gas processing train.

To address this critical issue, EastCoast has commissioned Petrofac Engineering Limited to undertake a capacity re-rating and debottlenecking review to assess how to meet the immediate and future projected demand. The results of this review are expected to be completed by the end of May 2006.

2005 highlights

- EastCoast earned a profit before tax of US$1.0 million and net cash flow from operations of US$1.8 million.
- Produced 14.7 bcf from the Songo Songo field in 2005, increasing the volume produced since the commencement of commercial operations in 2004 to 19.3 bcf. As operator of the wells and gas processing plant on Songo Songo Island, EastCoast did not record any downtime during 2005 that impacted the supply of gas to major customers in Dar es Salaam.
- Increased the gross certified proved (1P) and proved and probable (2P) recoverable reserves to be marketed by EastCoast by 41% to 241 bcf and 25% to 320 bcf respectively.
- Commenced gas sales to five new industrial customers in 2005 generating average sales during the year of 2.1 mmscf/d (2004:1.2 mmscf/d). During the seasonally low last quarter of 2005, an average of 3.3 mmscf/d was sold to the industrial sector.
- Signed an Interim Agreement to supply 19.5% of the gas consumption of the six turbines at the Ubungo Power Plant (maximum 9.1 mmscf/d) as Additional Gas. Under the terms of this agreement, EastCoast supplied an average of 8.1 mmscf/d at an average price of US$1.66/mcf. The Interim Agreement has been extended to 31 May 2006.
- Shot 589 kilometers of 2D seismic over the Songo Songo licence acreage and reprocessed 569 kilometers of existing 2D seismic.
- Signed a 382 square kilometer farm-in agreement with Ndovu Resources Limited, a subsidiary of Aminex plc, for licence acreage adjacent to the Songo Songo field. Acquired 328 kilometers of 2D seismic over this acreage. Interpretation should be complete by the end of May 2006.
- Signed new gas contracts in 2005 with Lakhani Industries Limited Textile and Murzah Oil Mills Limited for an estimated 0.5 mmscf/d. These customers will commence gas consumption in Q2 2006. In addition, three contracts were signed and gas production has commenced to Mukwano Industries (T) Limited and Tanzania Cigarette Company Ltd in Q1 2006.
- Completed the construction of 11 kilometers of new distribution pipeline bringing the total distribution system to 25 kilometers at the end of 2005. An additional 1 km was completed in Q1 2006.
- Successfully raised gross proceeds of Cdn$ 5.5 million through the issuance of 2.1 million Class B shares via a one for ten rights offering.

Photo: in 2005, Additional Gas supplied by EastCoast met 19.5% of the natural gas requirements of the Ubungo Power Plant at Dar es Salaam.

2006 targets

Our 2005 results have demonstrated that we are moving positively in the right direction and that momentum is building. Over 2006 we will continue to focus on growth.

- Negotiate and sign new contracts for the supply of gas for 245 MW (maximum estimated gas demand of 61 mmscf/d) of new power generation.
- Sign the long-term agreement for the supply of Additional Gas to the Ubungo Power Plant as a result of the addition of UGT 6 (maximum 9.1 mmscf/d).
- Continue to develop the industrial markets to reach a level of 5-6 mmscf/d by Q4 2006.
- Assess and if appropriate arrange financing for an increase in the capacity of the infrastructure system to enable up to 120 mmscf/d of peak gas rate to be transported to Dar es Salaam by mid-2007.
- Finalise plans for the drilling of a minimum of two wells in 2007. The initial priority will be on the exploration potential of Songo Songo West and increasing the deliverability in the main Songo Songo field.
- Raise approximately US$15 million – US$35 million through debt and equity to finance 2006/2007 developments.
- By 30 September 2006, in conjunction with Aminex plc, assess whether or not to drill a well on the Nyuni A licence acreage before November 2007.
- Continue to assess other opportunities within and outside Tanzania, and if these are comparable or better than existing programmes in Tanzania, to progress these.

We have made considerable progress in defining and building a substantial natural gas company over the past year. In noting EastCoast's achievements, management wants to acknowledge those who have stood with us and helped us to achieve the results that this Annual Report presents. We have relied on the investment of our shareholders; the skill, dedication and innovative spirit of our employees; the wise counsel of our Board of Directors; the commitment of our partners; the support of our customers and in particular the opportunities provided to us by the Government of Tanzania.

There is much to be done as we move through 2006 and we are already at work to meet our targets.

We have made considerable progress in defining and building a substantial natural gas company over the past year.

Peter R. Clutterbuck
President & CEO

25 April 2006

Operations Review

Production

During 2005 14.7 bcf of gas was produced from the Songo Songo field offshore Tanzania (an average of 40.3 mmscf/d). This brings total production since commercial operations commenced on 20 July 2004 to 19.3 bcf. Production peaked at 72.8 mmscf/d on 6 August 2005. The average production during October 2005 was 50.1 mmscf/d.

Operatorship

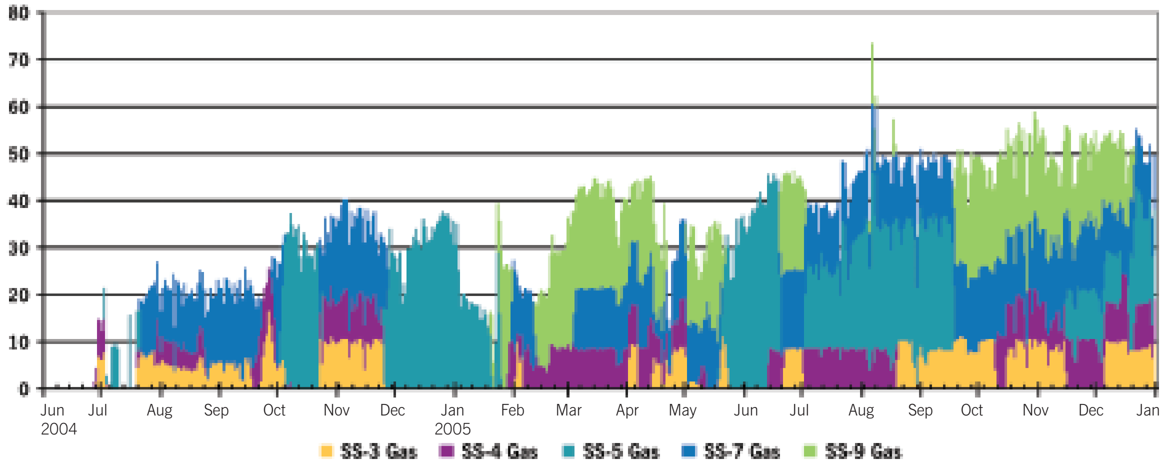
EastCoast is the operator of the wells and gas processing plant on Songo Songo Island on behalf of the stakeholders, including Songas Limited ("Songas"). Operatorship is on a 'no gain/no loss' basis. Two internationally experienced staff manage the site operations on a rotational basis with support from 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 year ended 31 December 2005, there were no unplanned shutdowns on Songo Songo Island that impacted the supply of gas to Dar es Salaam.

During 2005, the five operating wells at Songo Songo Island produced an average of 40.3 mmscf/d.

Songo Songo wells

The 2005 production from the five Songo Songo wells was as follows:

Well	Bcf
SS-3	1.3
SS-4	1.9
SS-5	3.9
SS-7	3.8
SS-9	3.8
Total	**14.7**



The total 2005 gas production of 14.7 bcf from Songo Songo's five wells was allocated as follows:

	Bcf
Protected Gas sales	11.9
Additional Gas sales	2.5
Flare, generator at the processing plant and line pack	0.3
Total	**14.7**

Protected Gas production

Under the terms of a Gas Agreement signed in 2001, the Protected Gas from Songo Songo is 100% owned by the Tanzanian Petroleum Development Corporation ("TPDC") and is sold to Songas under a 20 year Gas Agreement for the operation of five turbines at the Ubungo Power Plant ("Ubungo") or for onward sale to the Wazo Hill cement plant or village electrification.

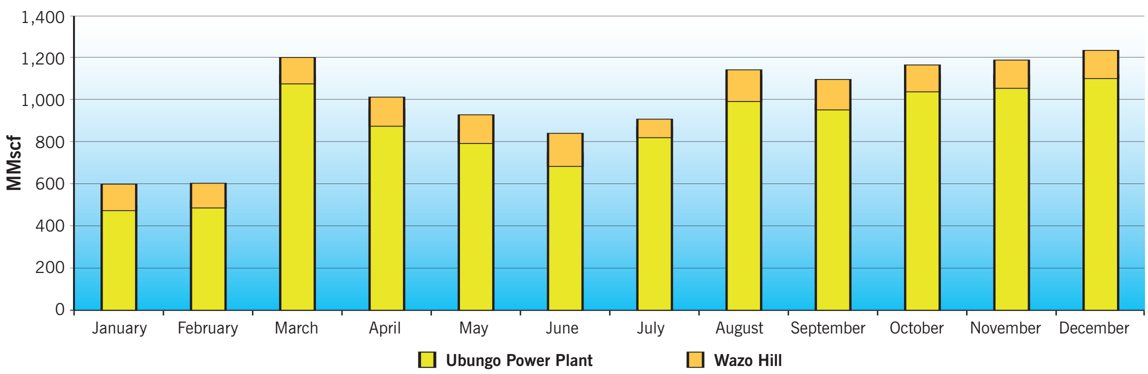
Over the year ended 31 December, 2005, the Protected Gas utilisation rate was 73%. Allocation of Protected Gas was as follows:

	Year ended 31 December 2005		
	Protected Gas consumed Bcf	mmscf/d	Utilisation rate %
PROTECTED GAS USER			
Ubungo Power Plant	10.3	28.3	74
Wazo Hill Cement Plant	1.6	4.3	73
Village Electrification Programme	–	–	–
Total consumption	**11.9**	**32.6**	**73**
Total consumption at 100% utilisation	**16.5**	**45.1**	**n/a**
Protected Gas not utilised	**4.6**	**n/a**	**n/a**

Utilisation by Protected Gas users was lower than anticipated in 2005. The utilisation rate at Ubungo was only 74% during 2005 despite record low water levels in the Mtera reservoir. This was as a result of the fifth turbine at Ubungo not being operational until March 2005. In addition, two of the Ubungo units had major failures and were not operational at various times between June and October 2005. During the last quarter of 2005, the utilisation of Protected Gas at Ubungo rose to 91%.

At Wazo Hill, utilisation ranged from 65% - 80% over 2005, except in July when the plant was shut down for maintenance. In addition, no gas was utilised by the Village Electrification Programme over 2005, but supply of gas is expected to commence in 2006.

Protected Gas demand by month



As a result, 4.6 bcf of gas was not utilised by the Protected Gas consumers in 2005 and became available as Additional Gas. The maximum gas required for the Protected Gas users over the remaining 18 years and seven months of the Gas Agreement was reduced to 306 bcf as at 31 December 2005. For the purposes of calculating the level of gas available as Additional Gas an assumption has to be made as to the expected utilisation of the Protected Gas users over the remaining term of the Gas Agreement. These assumptions are reviewed on an annual basis based on historic and projected usage.

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

Protected Gas consumer	Theoretical maximum 100% load factor (mmscf/d)	Most likely (mmscf/d)
UBUNGO		
Two ABB turbines	11.8	9.6
Two GE turbines	18.1	14.7
Fifth GE turbine	8.3	6.7
Sixth GE turbine (supplied by Additional Gas)	9.2	7.5
Total Ubungo	**47.4**	**38.5**
80.5% Ubungo from Protected Gas	**38.2**	**31.0**
WAZO HILL		
Kiln 1	3.4	2.7
Kiln 2	2.5	2.0
Total Wazo Hill	**5.9**	**4.7**
VILLAGE ELECTRIFICATION PROGRAMME	1.0	1.0
Total daily Protected Gas consumer demand (mmscf/d)	**45.1**	**36.7**
Protected Gas Reserves to end of the Songas power purchase agreement (Bcf)	**306**	**249**

The forecast theoretical maximum of Protected Gas has increased from 44.8 mmscf/d, as reported in 2004, to 45.1 mmscf/d based on technical tests of the Ubungo turbines. The potential utilisation of these turbines in the next few years has been increased in the ‘most likely’ case to take into account the lower utilisation of hydro electricity plants in Tanzania caused by a lack of rainfall. As a consequence, the expected utilisation rate of the Protected Gas usage has risen from 75% to 81% and Protected Gas requirements have increased by 4 bcf despite 12 bcf of Protected Gas being consumed during 2005.

Additional Gas production

Under the terms of a Gas Agreement signed in 2001, the Additional Gas from Songo Songo, in excess of the volume reserved as Protected Gas, is available to EastCoast to be marketed as Additional Gas.

In 2005 EastCoast expanded its Additional Gas sales to the industrial sector. Industrial sales in 2005 averaged 2.1 mmscf/d. This increased to 3.3 mmscf/d in Q4 despite this being a seasonally low quarter. As at 31 December 2005, the Company was selling gas to seven customers, namely Kioo Limited, Tanzania Breweries Limited, Bora Industries Ltd, Aluminium Africa Ltd, Karibu Textile Mills Ltd, Tanzania China Friendship Textile Co Ltd and Nida Textile Mills Ltd. In the peak summer months these customers are expected to take in excess of 4.5 mmscf/d.

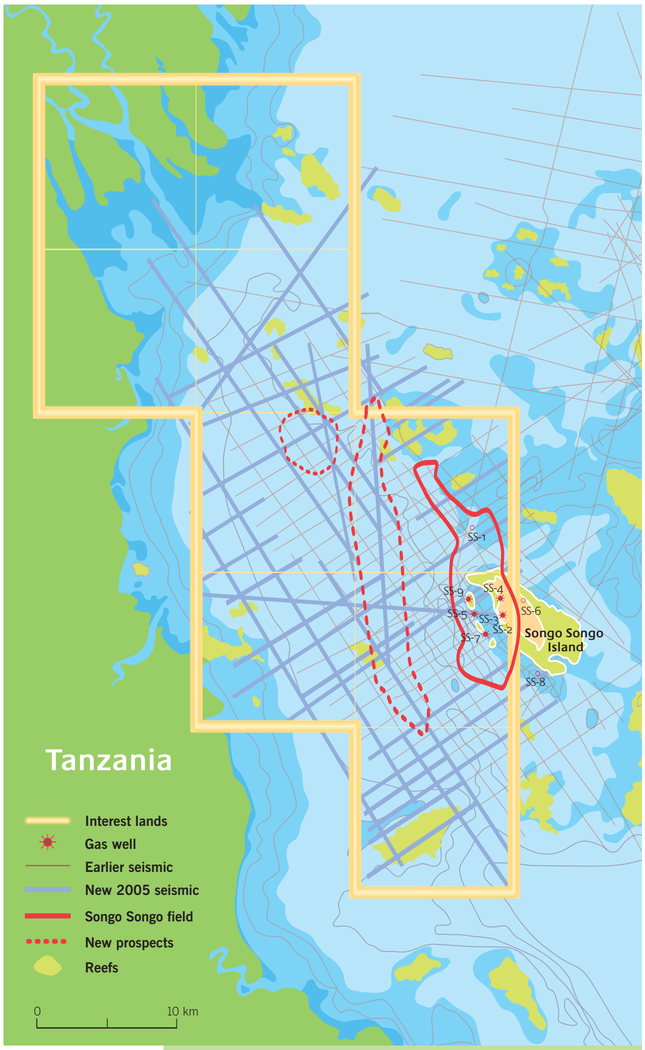
Flare, generator and line pack requirements

A relatively small amount of gas is required to be used in local electricity generation on Songo Songo Island. Gas is also required to maintain the Songo Songo Island gas plant flare at all times. These uses lead to a small loss of gas each year.

There are also fluctuations in the line pack in the 232 kilometer pipeline to Dar es Salaam. The line is estimated to hold a maximum of 85 mmscf of gas. At current production levels this is approximately 1-2 days of the required level of Protected and Additional Gas production required daily at Dar es Salaam.

Songo Songo field

During 2005, EastCoast gained a better understanding of the Songo Songo field and the adjacent licence acreage through reservoir surveillance and a remapping of the field. The reservoir surveillance incorporated engineering studies of well behaviour and pressure analysis. The remapping was a bottom-up exercise that included the field and surrounding areas. It utilised reprocessed and new seismic data and the acquisition of regional geological studies.



Songo Songo license blocks

Reservoir surveillance and management

Over 2005, the Company continued to acquire excellent information on the Songo Songo field from the downhole gauges that were installed in all wells (except SS-9). These highly accurate gauges record every pressure change and allow the Company to estimate the volume of gas in contact with each well and optimise production strategies. The pressure gauges were retrieved from the wells during July 2005 and January 2006 and have been re-installed to allow further evaluation later in 2006.

To compare the current condition of the wells and the reservoir with the anticipated performance before the field came on commercial production, the Company is analysing the pressure transients obtained from production and the downhole pressure data. In addition, the pressure data is being incorporated into material balance models that provide an independent assessment of the GIIP to compare with the geological mapping models. The pressure data extracted has been used to provide a preliminary assessment of aquifer support and the level of communication between the wells.

So far, the pressure data shows no evidence of strong aquifer support. The surface water cut has remained constant at a level that corresponds to condensation that is naturally present in the gas. This indicates that no aquifer water is reaching the wells. This will be carefully observed until at least 10% of the gas-in-place has been produced. In the case of Songo Songo, this represents approximately another three - four years of production. However, aquifer drive cannot be ruled out and will continue to be modelled as a possible outcome. The 2006 simulation studies will investigate this further.

Based on preliminary reservoir material balance calculations, the following is the calculated GIIP:

GIIP (bcf)	Most likely	Aquifer
SS-3	102	67
SS-4	62	35
SS-5	421	377
SS-7	295	266
SS-9	344	335
	1,224	**1,080**

EastCoast's GIIP numbers compare favourably with the 998 Bcf used by McDaniel & Associates Consultants Ltd. ("McDaniel") in its independent reserve report as at 31 December 2005. McDaniel calculated the GIIP primarily through volumetric structural mapping of the different reservoir zones rather than relying on the pressure data at this early stage in the field's development.

To obtain the most reliable data for reservoir management, the Songo Songo gas plant is equipped with a test separator that allows production from individual wells to be measured and important surface pressures and temperatures to be captured using Keller wellhead gauges. This information has been combined with the results of the downhole pressure gauges to show that SS-3, SS-4, SS-5 and SS-9 demonstrate conclusive evidence of communication with other wells. There is the possibility that SS-7 may be partially isolated from the other wells and this will be monitored during 2006, although compartmentalisation is not expected to be material.

The flow rates of the wells based on the requirement to have 1,600 pounds per square inch of pressure in the gas processing plant are as follows:

Songo Songo wells	Well flow rates (Mmscf/d)		
	1997 initial capacity forecast	31 December 2004 capacity forecast	31 December 2005 capacity forecast
SS-3	10	17	18
SS-4	10	19	17
SS-5	60	65	63
SS-7	20	22	22
SS-9 (Note 1)	40	35	25
Total	140	158	**145**
Maximum Protected Gas demand	(45)	(45)	(45)
Available Additional Gas	95	113	**100**

Note 1: SS-9 *-will produce at rates in excess of 25 mmscf/d, but the rate is currently being restricted to ensure that no downhole problems occur from gauges and wireline left in the hole in 1997.*

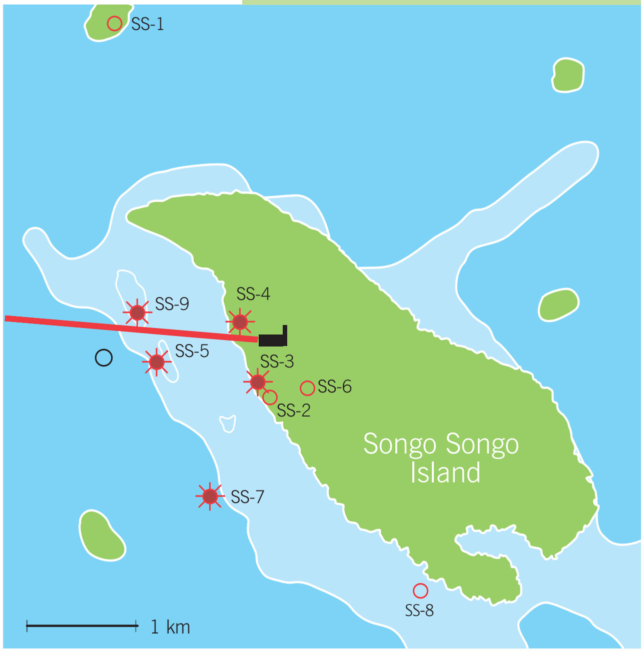
The Songo Songo wells showed less than a 2% decline over the course of 2005, in line with production expectations. The deliverability is still sufficient to enable 100 mmscf/d of Additional Gas production above the peak demand for Protected Gas. This will allow the Company to produce 37 mmscf/d of Additional Gas for a period of time even if the largest well, SS-5, becomes unavailable at peak demand.

SS-9 was tested in January 2005 and was produced at 35 mmscf/d. During 2005, it was concluded that the perforated tubing plug, downhole gauges and wireline left in the well were having an effect on the production rate and it was decided to restrict the flow to 25 mmscf/d. The deliverability of this well can be improved by working it over and removing the downhole gauges and wireline. It is estimated that a workover could increase SS-9 production to 60 mmscf/d. This would increase the deliverability of the field by another 35 mmscf/d over current levels.

Songo Songo remapping

In 2005 geophysical work concentrated on reviewing 569 kilometers of reprocessed 2D seismic and 212 kilometers of newly acquired 2D seismic gathered over the main Songo Songo field. The geophysical studies focussed on improving the definition of the key reservoir intervals by incorporating a review of the core material, the well logs and studying the shallow Eocene formation. The data have been combined with improved structural information to prepare a detailed geological model of the field. The assessed GIIP supports the McDaniel's GIIP as incorporated in their independent reserve evaluation.

Songo Songo gas field



Additional Gas Reserves

In accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities, the independent petroleum engineers, McDaniel prepared a report dated March 2006 that assessed the EastCoast natural gas reserves based on information on the Songo Songo field as at 31 December 2005 (the "McDaniel Report").

Over the course of 2005, there has been a 41% increase in Songo Songo's gross 1P reserves from 171.2 bcf to 240.6 bcf. Gross 2P reserves increased 25% from 255.4 bcf to 320.0 bcf. The reserves summary to the end of the license period (October 2026) for the gross Additional Gas was as follows:

Songo Songo Additional Gas reserves to 2026 (Bcf)	2005 Gross (1)	2005 Net (2)	2004 Gross	2004 Net
INDEPENDENT RESERVES EVALUATION				
Proved producing	179.9	108.5	124.6	66.2
Proved undeveloped	60.7	44.0	46.6	35.6
Total Proved (1P)	**240.6**	**152.5**	**171.2**	**101.8**
Probable	79.4	72.3	84.2	39.3
Total Proved and Probable (2P)	**320.0**	**224.8**	**255.4**	**141.1**

(1) *Gross reserves are based on 100% of the property's gross Additional Gas reserves (excluding Protected Gas).*
(2) *Net reserves are based on the Company's share of the Cost Gas and Profit Gas revenues.*

For the purpose of calculating the gross Additional Gas reserves, McDaniel has assumed that 249 bcf will be required to meet the demands of the Protected Gas users from 1 January 2006 to October 2026. This compares with 249 bcf at 1 January 2004. During 2005, Protected Gas users consumed 11.9 bcf.

On a life-of-field basis the gross recoverable proven reserves and the proven and probable reserves have increased to 276.2 bcf (net 175.1 bcf) and 447.5 bcf (net 305.7 bcf) respectively.

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

Year	Brent crude	Additional Gas price 1P	Additional Gas Volumes 1P	Additional Gas price 2P	Additional Gas Volumes 2P	Annual Inflation
	US$/BBL	US$/*mcf*	*mmscf/d*	US$/*mcf*	*mmscf/d*	%
2006	57.50	3.92	12.6	3.92	12.6	2.5
2007	55.40	3.66	17.9	3.76	17.9	2.5
2008	52.50	2.88	35.2	3.01	35.2	2.5
2009	49.50	2.88	40.1	3.01	40.1	2.5
2010	46.90	2.94	40.9	3.08	40.9	2.5
2011	48.10	3.08	41.9	3.21	41.9	2.5
2012	49.30	3.16	41.9	3.29	41.9	2.5
2013	50.50	3.23	41.9	3.37	41.9	2.5
2014	51.80	3.32	41.9	3.46	41.9	2.5
2015	53.10	3.40	41.9	3.54	41.9	2.5
2016	54.40	3.94	25.2	3.63	41.9	2.5
2017	55.80	3.82	25.2	3.73	41.9	2.5
2018	57.20	4.14	25.2	3.82	41.9	2.5
2019	58.60	4.24	25.2	3.91	41.9	2.5
2020	60.10	4.35	25.2	4.01	41.9	2.5
2021	61.30	4.45	25.2	4.11	41.9	2.5
2022	62.53	4.55	25.2	4.20	41.9	2.5
2023	63.78	4.65	25.2	4.30	41.9	2.5
2024	65.05	4.75	25.2	4.40	41.9	2.5
2025	66.36	4.86	25.2	4.50	41.9	2.5
Thereafter	+2.5%	+2.5%	25.2	+2.5%	41.9	2.5%

The price of Additional Gas for the industrial sector has been priced at 90% of the price of Brent Oil, less 22.5% for the discount offered to the customers.

Additional Gas for the power sector is priced at US$2.00/mcf in 2006 and then US$2.25/mcf, escalating with inflation for the proven case and US$2.40/mcf escalating with inflation in the proven and probable case from 2007.

Additional Gas reserves reconciliation

B*cf*	Gross Proved	Gross Proved and probable	Net Proved	Net Proved and probable
Reserves at 1 January 2005	**171.2**	**255.4**	**102.0**	**141.1**
Extensions	-	–	–	–
Improved recovery	–	–	–	–
Technical revisions	71.9	67.1	52.5	85.7
Discoveries	–	–	–	–
Acquisitions	–	–	–	–
Dispositions	–	–	–	–
Economic factors	–	–	–	–
Production	(2.5)	(2.5)	(2.0)	(2.0)
Reserves at 31 December 2005	**240.6**	**320.0**	**152.5**	**224.8**

There was no development activity on the Songo Songo field during 2005. The increase in the proven reserves has arisen from the 2005 pressure and gas production data and the Songo Songo remapping work.

It is expected that the 2006 Songo Songo work program, including the creation of a simulation model that will be undertaken on the field and adjoining acreage, will provide additional clarity on the level of the reserves and the impact of the aquifer. A new independent reserve report may be commissioned once the simulation model is complete.

Two trains are used to process gas production from the Songo Songo field.

Present value of reserves

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

US$ millions		2005			2004	
	5%	10%	15%	5%	10%	15%
Proved producing	76.4	47.4	33.4	32.5	22.3	16.6
Proved undeveloped	26.7	20.3	13.8	19.2	13.2	9.0
Total Proved (1P)	**103.1**	**67.7**	**47.2**	**51.7**	**35.5**	**25.6**
Probable	38.1	16.1	7.1	12.9	7.9	5.7
Total Proved and Probable (2P)	**141.2**	**83.8**	**54.3**	**64.6**	**43.4**	**31.3**

The present values are primarily higher in 2005 due to the increase in the reserves and the fact that there has been an increase in the forecast capital expenditure which has the effect of reducing the amount of Additional Profits Tax that is payable.

Exploration

There are nine licences included in the Company's PSA with the TPDC, namely the two blocks within which the Songo Songo field lies ("Discovery Blocks") and seven blocks in adjacent areas ("Adjoining Blocks"). In addition, during 2005, the Company entered into a farm-in agreement with a subsidiary of Aminex plc for 382 square kilometers of their Nyuni licence acreage ("Nyuni A").

During the course of 2005, the Company acquired 917 kilometers of new 2D seismic using the Geomariner survey vessel.

Exploration Survey Area	Kilometers
Discovery Blocks	212
Adjoining Blocks	377
Nyuni A farm-in area	328
	917

In addition the Company reprocessed 569 kilometers of the old 2D seismic over the licence acreage. All of the data have been processed and interpreted conclusions and intentions in relation to these blocks are outlined below.

Unproven section of Discovery Blocks

A review of the seismic on the Discovery Blocks has identified a promising prospect approximately 2 kilometers west of the existing Songo Songo field. This has been designated as Songo Songo West ("SSW").

The seismic on SSW indicates a tilted fault trap at the same reservoir interval (Neocomian) as the main field. In addition, there is a direct hydrocarbon indicator in the northern aspect of the field that could indicate the presence of gas.

Estimated potential if exploration successful	Minimum GIIP Bcf	Most likely GIIP Bcf	Maximum GIIP Bcf
DISCOVERY BLOCKS			
Songo Songo West	90	600	1,070

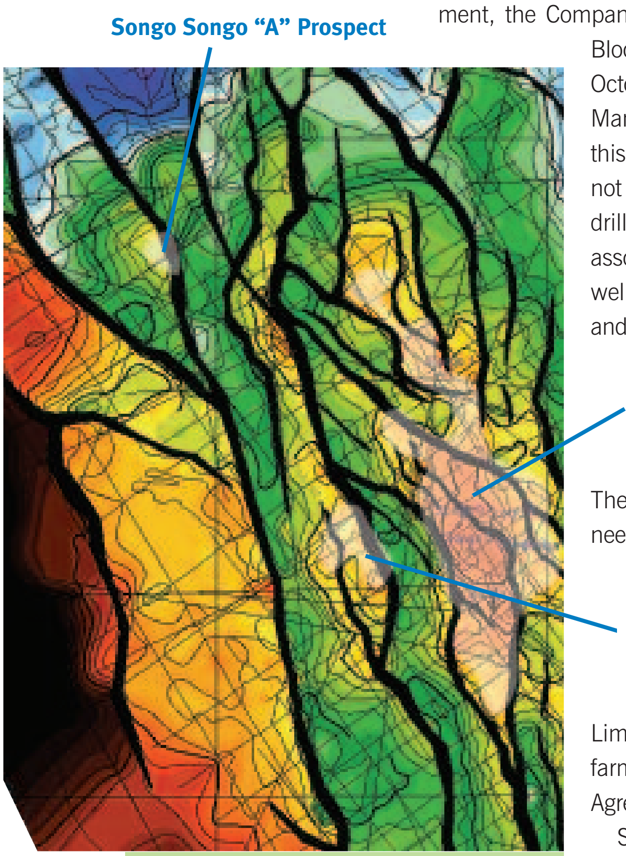
EastCoast intends to drill one well in the northern aspect of SSW in the next 12 -18 months with the possibility of drilling a second well if the first is successful. The timing will depend on rig availability, lead times for purchasing casing and the raising of funds to finance drilling.

The potential exploration drilling locations are in water depths of approximately 20 meters and will require a small semi-submersible or a jack-up rig. The Company has provisionally tendered for a jack-up rig. However, it is unlikely that a rig will be available before Q1 2007. It is estimated that the first SSW well will cost US$10 million including mobilisation and demobilisation costs. Each subsequent well will cost approximately US$5 million. An additional US$3 million would be required to complete each commercial well.

Adjoining Blocks

377 kilometers of new 2D seismic was acquired on the Adjoining Blocks in the adjacent areas to the Discovery Blocks. This has highlighted a small accumulation ("Lead A"). It is at the same Neocomian interval as the Songo Songo field, but there is greater uncertainty about the fault seal than with SSW.

Under the terms of the Songo Songo PSA and a subsequent agreement, the Company had to commit to drill a well on the Adjoining Blocks before 11 January 2006 and to drill it by 11 October 2006 in order to retain the Adjoining Blocks. Management was of the view that the relative size of this accumulation and the risk associated with it did not warrant the drilling of a well on this lead before the drilling of SSW. Management also perceived the risk associated with Lead A to increase if the drilling of a well on SSW is unsuccessful. The Ministry of Energy and Minerals ("MEM") has indicated that if this structure is drilled by 11 April 2007 regardless of the outcome of SSW then the Company can retain the Adjoining Blocks. The Company is currently evaluating this offer and needs to respond to MEM by 30 April 2006.



Exploration prospect areas

Nyuni "A"

In September 2005, EastCoast entered into an agreement with Ndovu Resources Limited ("Ndovu"), a subsidiary of Aminex plc, to farm-in to its offshore Nyuni Production Sharing Agreement ("Nyuni PSA") adjacent to the producing Songo Songo gas field.

Under the agreement, Ndovu and EastCoast will negotiate with TPDC to divide the Nyuni PSA into two areas, A and B. Area A will consist of the western portion of the PSA. Area B will cover the balance of the PSA area and will include the Nyuni prospect that was drilled by Aminex plc and partners in 2003/4 with reported oil shows.

EastCoast acquired 328 kilometers of 2D seismic over Nyuni A in October 2005 taking advantage of the cost savings gained by extending the Songo Songo area 2D seismic program. A few prospects have been identified and will be interpreted by the end of May 2006.

As a result of undertaking the seismic work, the Company has until 30 September 2006 to elect whether to participate in the drilling of a well on Nyuni A to earn an interest in the Nyuni PSA. The well would have to be drilled by November 2007. If the Company elects to drill, it will pay either 42% to earn a 35% interest in Area A or 64% to earn a 50% interest. The cost of any Nyuni well can only be recovered out of future revenues from the Nyuni PSA.

The parties have agreed that any discovery will be developed jointly with Aminex plc and operated by EastCoast.

2005 geophysical program

Infrastructure

The infrastructure that transports the gas from the field to Dar es Salaam was commissioned in July 2004. The current infrastructure configuration has a name plate capacity of approximately 70 mmscf/d, limited by the two gas processing trains that have a design specification of 35 mmscf/d each. The Company is of the view that between 80 mmscf/d and 105 mmscf/d could be processed without any additional investment, since 42 mmscf/d has been processed through a single processing train for a short period of time. Of this capacity, a maximum of 45 mmscf/d has to be available for the Protected Gas users.

The Company has recently contracted Petrofac Engineering Limited ("Petrofac") to conduct a re-rating and debottlenecking review with the objective of identifying the most efficient means of increasing the peak capacity to Dar es Salaam to approximately 120 mmscf/d over the next 18 months.

The Petrofac report will assess the most efficient method of installing a third gas processing train which is estimated to be able to increase the gas processing plant capacity to in excess of 120 mmscf/d. Songas has indicated that it may, under certain conditions, finance the third train. Alternatively, there are provisions in the Songo Songo agreements that would enable EastCoast to finance and install a train. This is currently being evaluated and a proposal will be put forward to MEM. If a third train is installed, it is forecast that the infrastructure capacity will then be limited by the offshore and onshore pipeline at approximately 105-110 mmscf/d.

At Dar es Salaam EastCoast continued to expand its distribution system during 2005. An 8 kilometer extension to Karibu Textile Mills Ltd. was completed in May 2005 and a 4 kilometer extension to Lakhani Industries Limited Textile and Murzah Oil Mills Limited was 75% complete at the year end. Once the current system is complete, the Company will have 26 kilometers of distribution pipeline. Another 12 kilometers is planned to be constructed in 2006/2007 to connect new customers and to close the ringmain. This closure will more than double the capacity of the existing system to a peak of 20 mmscf/d and ensure security of supply.

At Dar es Salaam, EastCoast continued to expand its distribution system over 2005 to connect industrial gas users.

Markets

Current industrial sales

The Company continued to expand sales to the industrial sector during 2005. Industrial gas sales in 2005 averaged 2.1 mmscf/d and this increased to 3.3 mmscf/d in Q4 2005, despite this being a seasonally low demand period. As at 31 December 2005, the Company was selling gas to seven customers – Kioo Limited, Tanzania Breweries Limited, Bora Industries Ltd, Aluminium Africa Ltd, Karibu Textile Mills Ltd, Tanzania China Friendship Textile Co Ltd and Nida Textile Mills Ltd. In the peak summer months these customers are expected to purchase in excess of 4.5 mmscf/d.

Market expansion potential

The Company has signed additional contracts with Lakhani Industries Limited Textile, Murzah Oil Mills Limited, Mukwano Industries (T) Limited, Serengeti Breweries Limited and Tanzania Cigarette Company Ltd. These customers will consume 0.5 mmscf/d as from Q2 2006 rising to 0.8 mmscf/d from Q3.

The price achieved for the industrial sales averaged US$7.07/mcf during 2005. The Company sells the gas to the industrial sector at a 20% – 25% discount to the price of Heavy Fuel Oil ("HFO") in Dar es Salaam. The price of HFO in Dar is linked to the world prices for oil with a slight time lag.

Current power sales

During the year, Songas Limited ("Songas") added a sixth turbine ("UGT 6") at the Ubungo Power Plant pursuant to the signing of a power purchase agreement with TANESCO. UGT 6 is located alongside turbines UGT 1-5 that are contracted to purchase Protected Gas under the terms of the Songo Songo project agreements.

An Interim Agreement with Songas for the supply of Additional Gas was signed on 1 October 2005. In accordance with the terms of this Interim Agreement, 19.5% of all the gas that is supplied to the six turbines at the Ubungo Power Plant is considered Additional Gas. This percentage represents the volume of gas required for UGT 6 in proportion to the total consumption of the six turbines.

This Interim Agreement was initially to cover the period from the commencement of UGT 6 on 8 June 2005 to 31 December 2005. However, it has been agreed to extend the Interim Agreement to 31 May 2006, considering other ongoing power negotiations.

From the commencement of UGT 6 operation, the Company sold 1,672 mmscf of Additional Gas to Songas or an average of 8.1 mmscf/d. This compares with the maximum daily volume of 9.1 mmscf/d. The utilisation rate was achieved despite the major failures of both UGT 1 and UGT 3 during the period that led to UGT 3 being removed to Canada for repairs and UGT 1 having its blades repaired on site.

In 2005, EastCoast continued to add industrial customers for Additional Gas including Tanzania China Friendship Textile Co.

As a result of these turbine failures, TANESCO had to generate electricity at the IPTL power plant utilising expensive heavy fuel oil as its feedstock, Accordingly the Company agreed to provide TANESCO with some relief by pricing the Additional Gas with a sliding scale of prices that are lower if the turbines are unavailable because of mechanical failure for a significant period of time. Therefore, under the Interim Agreement, the Additional Gas was priced at between US$2.32/mmbtu (US$2.15/mcf) and US$0.67/mmbtu (US$0.62/mcf) and averaged US$1.66/mcf in 2005. The long term Agreement is expected to retain an availability clause linked to UGT 6 with similar pricing terms escalating with U.S. consumer price inflation.

Prospective Markets

Current demand exceeds the reserves as assessed by McDaniel and accordingly new gas reserves will be needed to satisfy market demand.

The following summarises potential demand requirements to 2010.

	2006 Target	2008 Target	2010 potential demand
MM*scf/d*		(*Note* 1)	(*Note* 2)
Industrial	4.5	7.3	20.0
Power	8.1	51.0	85.0
Compressed Natural Gas	–	–	5.0
	12.6	**58.3**	**110.0**

Note 1: *This is dependent on the signing of the current power contracts under discussion that may or may not materialise. This level of sales is higher than the* McDaniel 2P *plateau of* 41.9 *mmscf/d and therefore requires new reserves if it is to be maintained over the term of the* PSA.

Note 2: *This provides an indication of the potential demand where significant new reserves are located.*

EastCoast's presence on Songo Songo Island has improved the quality of life for local residents. Regular school programs, smart uniforms and a secure supply of fresh water are part of the company's community relations.

Prospective industrial sales

The Company's target is to increase industrial gas sales from an average of 3.3 mmscf/d during Q4 2005 to an average of 5-6 mmscf/d by the end of 2006. To achieve this, EastCoast needs to close the existing distribution system at an estimated cost of US$2.5 million so that there is sufficient security of supply and system capacity.

A number of current customers have indicated a desire to expand their operations, including the generation of their own electricity. With expansion, EastCoast's existing customers are expected to purchase approximately 7.0 mmscf/d by the end of 2007.

In addition, with an investment of a further US$2.5 million, the Company projects that over the next 18 months an additional 2-3 mmscf/d of new customers can be connected approximately 8 kilometers north of the Ubungo Power Plant.

It is anticipated that a number of companies looking to establish manufacturing facilities in East Africa will be attracted to Tanzania by the relatively low cost of energy, a stable economy and a stable investment climate. Accordingly the Company anticipates that the industrial demand in Tanzania will continue to grow as new industries relocate in areas adjacent to the gas infrastructure. Some of these companies could have significant demand, as would be the case with a fertiliser plant.

There are a number of industries located outside of Dar es Salaam that are commercially accessible by pipelines in a US$40/barrel environment. Tanga is 300 kilometers north of Dar es Salaam and only 60 kilometers from the Kenya border. It has approximately 10 mmscf/d of gas demand, including the second largest cement plant in Tanzania. 180 kilometers west of Dar es Salaam is Morogoro where there are several tobacco manufacturers and other industries with a forecast demand of 7-9 mmscf/d. The Company will assess whether it is more viable to construct pipelines to these customers or to transport Compressed Natural Gas.

If there are sufficient gas reserves and infrastructure capacity, there is the potential for 20 - 30 mmscf/d to be sold to the industrial sector in Tanzania by 2010.

The number of industrial customers in the Dar es Salaam area has increased significantly.

Prospective power sales

As at 31 December 2005, Tanzania had approximately 851 MW of installed electrical power generation as follows:

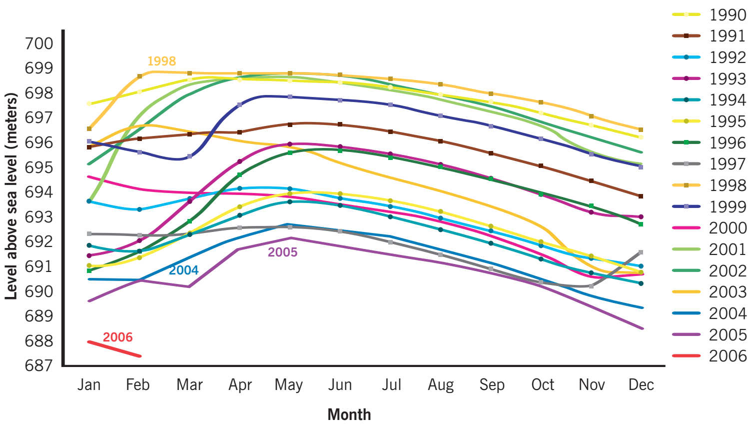
Feedstock	Power Plant	Installed capacity MW
Hydro:	Kidatu	204
	Mtera	80
	Hale	21
	Pangani Falls	68
	Kihansi	180
	Others	8
		561
Gas fired:	Ubungo (units 1-6)	**190**
Other thermal:	Independent Power of Tanzania Limited ("IPTL")	**100**
Total		**851**

The majority of Tanzania's generation is hydro and is dependent on the level of the rain during its rainy seasons. The only major water storage is at the Mtera reservoir that supplies the 80 MW Mtera hydro plant and further down-stream, the 204 MW Kidatu hydro plant. The level of the Mtera reservoir is integral to the generation of 284 MW.

In the last three years there have been lower than average rainfalls, which has resulted in the hydro generation in December 2005 being only 40% of its theoretical maximum, with Mtera generating only 30 MW and Kidatu 100 MW. In January 2006, TANESCO requested that it run the Mtera turbines below the 690 meter recommended minimum levels. By the beginning of February the Mtera reservoir was below 688 meters.

As a result, TANESCO recently commenced load shedding at up to 14 hours a day and is looking at several new generation projects to meet the current shortfall and projected increases in demand. In February 2006, TANESCO tendered for 200 MW of gas fired generation at Dar es Salaam (100 MW lease plant to be installed by 31 August 2006 and 100 MW of long term generation to be installed by 31 December 2006). The lease plant is forecast to be operational until the IPTL 100 MW power plant is fully converted to take gas. This power capacity expansion is in addition to a 45 MW plant due to be operational at Tegeta in Dar es Salaam by January 2007. It is forecast that these plants may not be operational within this timeframe given a number of issues that need to be resolved.

Mtera reservoir monthly levels



It is forecast that the maximum anticipated demand from the power sector could materialize by Q1 2008, although the exact configuration of the units may vary. 245 MW of new generation will require an estimated maximum of 61 mmscf/d of Additional Gas or 43 mmscf/d at a 70% load factor. It is anticipated that these units will run at high load factors in the short term to allow the water reserves to rebuild. In the event that there are above average rainfalls and the Mtera dam returns to normal conditions, it is forecast that the utilisation rate of the gas plants will be approximately 70% to meet peak daily demands and demand during the dry seasons.

TANESCO has also indicated that it intends to install another 250 MW of gas fired generation at Kinyerezi in Dar es Salaam by 2010. This would require an additional peak of 62 mmscf/d of Additional Gas or 43 mmscf/d at a 70% load factor.

Part of this generation is likely to be exported to Kenya. Kenya currently has approximately 1,056 MW of generation – 677 MW hydro, and 379 MW thermal and geothermal. The hydro is highly dependent on the 120 square kilometer Masinga reservoir that is the feedstock for 543 MW of hydro generation. Kenya was prone to droughts in the 1990s and the current drought in Tanzania is also being felt in Kenya. There are concerns that there may be load shedding in Kenya later in 2006.

This has caused Kenya to look for ways to reduce its reliance on hydro. As a consequence of the last major drought in 1999/2000, Kenya introduced three new thermal plants in Mombasa and an additional 45 MW in Nairobi. In 2002, Kenya entered into a contract with Uganda for the supply of 50 MW of electricity through an existing 80 MW transmission line between Owen Falls in Uganda and Nairobi. However, this export from Uganda is dependent on the completion of the Bujugali hydro plant which will not be commissioned until at least 2010. In addition, 95% of Uganda's power generation is hydro with a capacity of only 265MW. The low level of the water in Lake Victoria has reduced this to 170 MW and short term thermal generators have been introduced in Uganda to make up the shortfall. It is anticipated that all the Bujugali generation will be absorbed in the local market and there will be no power available for export.

The reliance on hydro in Uganda, Kenya and Tanzania, and the relatively high cost of alternative oil fired generation, has increased the likelihood that Dar es Salaam will become the thermal hub for East Africa provided there are sufficient gas reserves. The Kenyans and Tanzanians are considering the potential of importing hydro generated electricity from Zambia. But this would require substantial capital expenditures and long term commitments. The high capital costs of such an option makes gas a competitive solution.

The price charged for electricity in Tanzania remains a key factor in the assessment of generation options and project economics. Consumers in Tanzania currently pay approximately 7.5 cents/Kwh for their electricity. This tariff is the lowest in East Africa and significantly lower than the current prices in western economies. Since the Tanzanian Government is anxious to maintain a low electricity tariff, this puts some downward pressure on the long term price at which gas can be sold to the domestic power sector. However, in the short term, gas prices are forecast to average approximately US$2.15 - 2.30 rising annually in line with a pre-agreed formula.

Compressed natural gas (CNG)

The use of CNG is a proven technology that is widely used around the world including India and China. To examine the potential to use CNG in Tanzania, the Tanzanian Petroleum Development Corporation ("TDPC") visited China in November 2005 to see how CNG markets have been established and operated. In China, CNG is also used to supply domestic demand through the establishment of local distribution networks connected to CNG storage tanks. In May 2006, a combined EastCoast/TPDC delegation will revisit China.

The Company has identified two potential markets for CNG in Dar es Salaam – as a fuel for motor vehicles and for commercial and domestic use.

Motor vehicles

To introduce this application in Tanzania, EastCoast plans a demonstration project with one of its existing industrial customers to convert its distribution fleet to CNG. Fleet conversion to CNG could then be rolled out to other operations such as bus companies. It is anticipated that CNG could also be offered for use in domestic motor vehicles. During 2005, the Company submitted tender documents to organizations with experience in developing a CNG market for vehicles. As a result of this tender, EastCoast has entered into discussions with an international major oil company that has developed a similar project in Egypt.

Commercial and domestic

It is projected that the Company may offer CNG sales to the hotel industry displacing heavy fuel oil and liquid petroleum gas. Other new industrial markets will also be assessed to determine if they can be more economically served by transporting CNG instead of constructing a gas pipeline.

CNG market size

The potential CNG market in Dar es Salaam is estimated to be approximately 10 - 15 mmscf/d. Provided there are sufficient reserves to meet the near term industrial and power needs and the tax regime for CNG is clarified, EastCoast is targeting a CNG demonstration project for 2007. It is anticipated that, once introduced, CNG sales will gradually increase.

Management's Discussion & Analysis

Management's Discussion & Analysis

FORWARD LOOKING STATEMENTS

THIS MDA OF FINANCIAL CONDITIONS AND RESULTS OF OPERATIONS SHOULD BE READ IN CONJUNCTION WITH THE COMPANY'S FINANCIAL STATEMENTS FOR THE YEAR ENDED 31 DECEMBER 2005. THIS MDA IS BASED ON THE INFORMATION AVAILABLE ON 25 APRIL 2006. IT CONTAINS CERTAIN FORWARD-LOOKING STATEMENTS THAT INVOLVE SUBSTANTIAL KNOWN AND UNKNOWN RISKS AND UNCERTAINTIES, CERTAIN OF WHICH ARE BEYOND EASTCOAST'S CONTROL, INCLUDING THE IMPACT OF GENERAL ECONOMIC CONDITIONS IN THE AREAS IN WHICH THE COMPANY OPERATES, CIVIL UNREST, INDUSTRY CONDITIONS, CHANGES IN LAWS AND REGULATIONS INCLUDING THE ADOPTION OF NEW ENVIRONMENTAL LAWS AND REGULATIONS AND CHANGES IN HOW THEY ARE INTERPRETED AND ENFORCED, INCREASED COMPETITION, THE LACK OF AVAILABILITY OF QUALIFIED PERSONNEL OR MANAGEMENT, FLUCTUATIONS IN COMMODITY PRICES, FOREIGN EXCHANGE OR INTEREST RATES, STOCK MARKET VOLATILITY AND OBTAINING REQUIRED APPROVALS OF REGULATORY AUTHORITIES. IN ADDITION THERE ARE RISKS AND UNCERTAINTIES ASSOCIATED WITH GAS OPERATIONS. THEREFORE, EASTCOAST'S ACTUAL RESULTS, PERFORMANCE OR ACHIEVEMENT COULD DIFFER MATERIALLY FROM THOSE EXPRESSED, OR IMPLIED BY, THESE FORWARD-LOOKING ESTIMATES AND, ACCORDINGLY, NO ASSURANCES CAN BE GIVEN THAT ANY OF THE EVENTS ANTICIPATED BY THE FORWARD LOOKING ESTIMATES WILL TRANSPIRE OR OCCUR, OR IF ANY OF THEM DO SO, WHAT BENEFITS, INCLUDING THE AMOUNTS OF PROCEEDS, THAT EASTCOAST WILL DERIVE THEREFROM.

THE COMPANY EVALUATES ITS PERFORMANCE BASED ON EARNINGS AND CASH FLOWS. CASH FLOW FROM OPERATING ACTIVITIES IS A NON-GAAP (GENERALLY ACCEPTED ACCOUNTING PRINCIPLES) TERM THAT REPRESENTS EARNINGS BEFORE DEPLETION, DEPRECIATION AND STOCK-BASED COMPENSATION. IT IS A KEY MEASURE AS IT DEMONSTRATES 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 AND TAX 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") principal 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 kilometer spur to the Wazo Hill Cement Plant.

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

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

Principal terms of the PSA and related agreements

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

Obligations and restrictions

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

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

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

(c) The Company 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 was for the period from October 2001 to October 2005 (extended to 11 January 2006 at the request of TPDC to the Ministry of Energy and Minerals ("MEM")). During this period, the Company was required to conduct a market survey, spend at least US$2.0 million (in October 2001 terms) on seismic or other field expenditures acceptable to TPDC, commit to drill one exploration well in the Adjoining Blocks, demonstrate to MEM compliance with submitted Additional Gas plans and make diligent attempts to sell Additional Gas. The Company acquired 589 kilometers of 2D seismic on the licence acreage during October 2005 using the Geomariner survey vessel and the interpretation of the seismic revealed a small accumulation ("Lead A"). However, management has not yet committed to the drilling of a well on Lead A. The MEM has indicated that provided the Company commits to drill a well by 30 April 2006 and drills it by 11 April 2007, it may retain the Adjoining Blocks. The Company is currently evaluating this offer. In the event that the Company relinquishes the Adjoining Blocks, there is no impact on the rights under the PSA to the Discovery Blocks and the potential of the existing field and the Songo Songo West prospect.

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

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

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

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

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

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

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

Access and development of infrastructure

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

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

Revenue sharing terms and taxation

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

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

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

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

In September 2001, the GoT made a formal request to the World Bank for funds to increase the diameter of the onshore pipeline from 12 inches to 16 inches at a projected incremental cost of US$3.5 million. The World Bank agreed to finance this increase and accordingly the pipeline capacity was increased from circa 65 mmscf/d to 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 and therefore, the comparative figures are for the four months ended 31 December 2004. 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

2005 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 ("Cost Gas"). 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 ("Profit Gas").

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

(US$'000 *except production and per mcf data*)	**Year ended 31 December 2005**	Period ended 31 December 2004
Gross sales volume (mcf):		
Industrial sector	776,607	120,593
Power sector	1,671,538	–
Total volumes	2,448,145	120,593
Average sales price (US$/mcf):		
Industrial sector	7.07	5.31
Power sector	1.66	–
Average price	3.37	5.31
Gross sales revenue	8,262	640
Gross tariff for processing plant and pipeline infrastructure	1,308	97
Gross revenue after tariff	**6,954**	**543**
Analysed as to:		
Company Cost Gas	5,216	407
Company Profit Gas	436	34
Company operating revenue (see Note 1)	**5,652**	**441**
TPDC Profit Gas	1,302	102
	6,954	**543**
OPERATING COSTS FOR ADDITIONAL GAS:		
Ring main distribution pipeline	187	36
Share of well maintenance	108	19
Other field and operating costs	200	23
Production and distribution expenses	495	78
Depletion	818	35

Note 1 *The Company's total revenues for the year amounted to US$5,759,000 after adjusting the Company's operating revenue of US$5,652,000 by:*

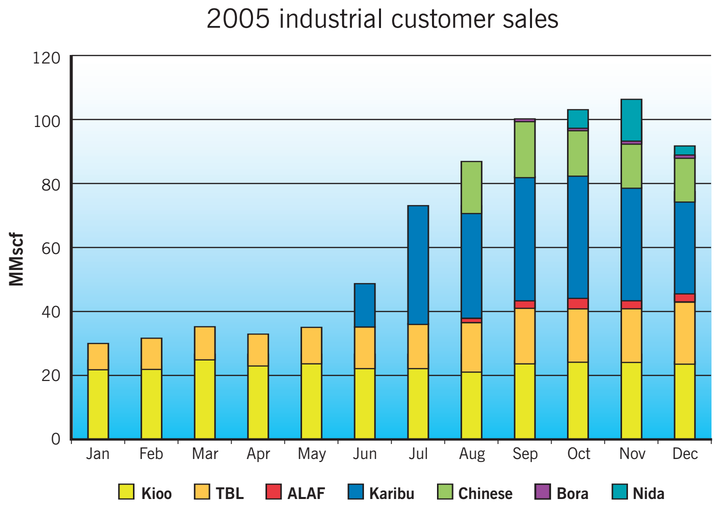
i) US$187,000 for income tax. The Company is liable for income tax in Tanzania, but the income tax is recoverable out of TPDC's Profit Gas when the tax is payable. To account for this, revenues are grossed up for the income tax and the tax is shown separately;

ii) US$80,000 for the deferred effect of Additional Profits Tax. This tax is netted off revenue as a royalty.

Volumes

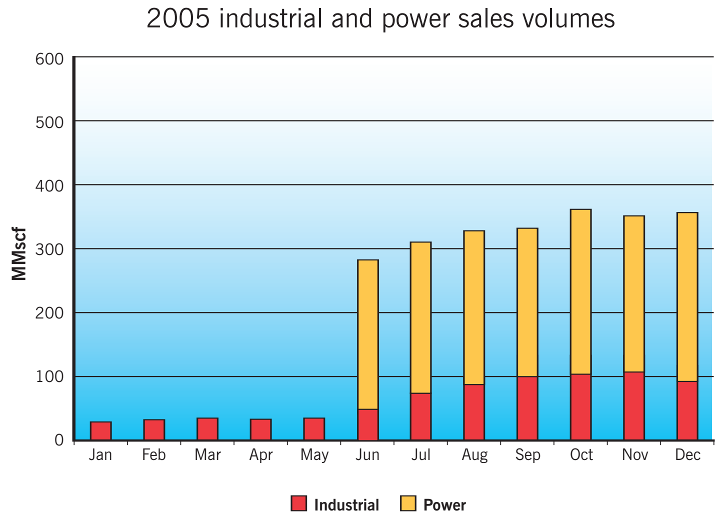
Industrial

The Company commenced Additional Gas sales to industrial customers on 18 September 2004. As a result, the sales for 2004 are for the four months ended 31 December 2004 as compared to the whole year in 2005. During the year, the Company commenced gas sales to five new industrial customers namely Karibu Textile Mills Limited, Tanzania-China Friendship Textile Limited, Nida Textile Limited, Aluminium Africa Limited and Bora Industries Limited. Industrial sales averaged 2.1 mmscf/d (2004: 1.2 mmscf/d) and peaked at 3.6 mmscf/d in November 2005.



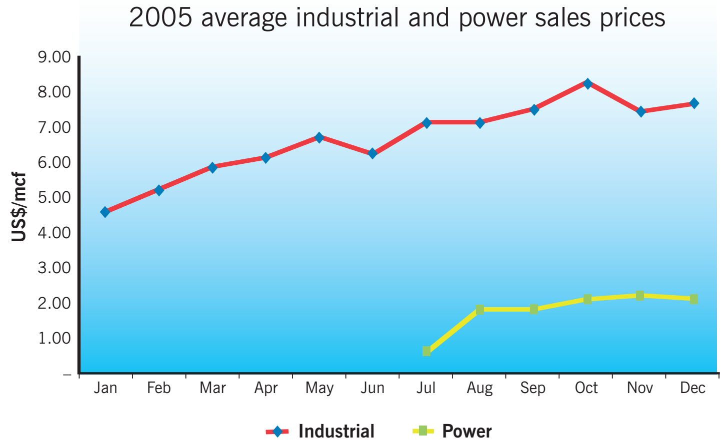
Power

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 the Ubungo Power Plant are considered Additional Gas. Between the commencement of UGT 6 on 8 June and 31 December, 1,672 mmscf was consumed at an average of 8.1 mmscf/d. The Interim Agreement expired on 31 December 2005 but the parties agreed to extend its terms to 31 May 2006 to allow for time to negotiate a longer term agreement within the context of increasing demand by the power sector for a number of different projects.



Pricing

Industrial

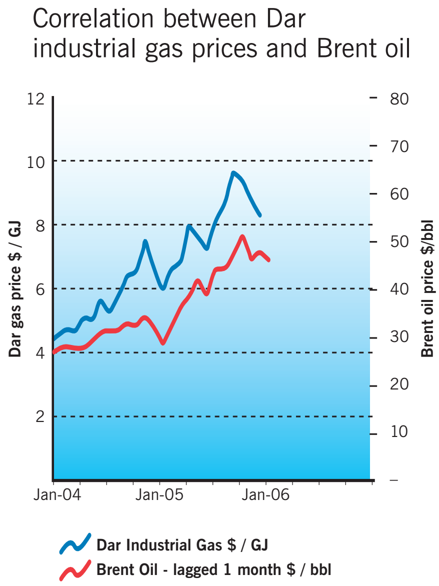


The price of gas during 2005 for the industrial sector was at a discount to the price of Heavy Fuel Oil ("HFO") in Dar es Salaam. This resulted in average gas prices of US$7.07/mcf (2004: US$5.31/mcf) during the year.

The gas price achieved for the industrial sector will fluctuate with world oil prices and the discount agreed with the customers. The monthly Additional Gas price sold to industrial customers in Dar es Salaam in 2005 ranged from US$4.56/mcf in January 2005 to US$8.24/mcf in October 2005.

Power

The price of gas from the commencement of power sales on 8 June 2005 averaged US$1.66/mcf. The Interim Agreement for the sale of Additional Gas to the Ubungo Power Plant provided for different gas prices, depending on the average availability of the six turbines, from the minimum of US$0.67/mmbtu (US$0.62/mcf) to the maximum of US$2.32/mmbtu (US$2.15/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 (US$0.62/mcf) was used for Additional Gas supplied from 8 June 2005 to 31 July 2005. The maximum price of US$2.32/mmbtu (US$2.15/mcf) was achieved in November and December 2005.



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$7.07/mcf (2004: 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. 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 year was US$437,000 (2004: US$96,000) and US$108,000 (2004: US$19,000) was allocated for the Additional Gas.

Other operating costs include an apportionment of the annual PSA licence costs, costs associated with the evaluation of the reserves and local levies charged on the basis of sales made.

Netbacks

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

(Amounts in US$/mcf)	Year ended 31 December 2005	Period ended 31 December 2004
Gas price – industrial	7.07	5.31
Gas price – power	1.66	–
Average price for gas	**3.37**	**5.31**
Tariff (after allowance for the Ringmain Tariff)	(0.53)	(0.80)
TPDC profit share	(0.53)	(0.85)
Net selling price	**2.31**	**3.66**
Well maintenance and other operating costs	(0.12)	(0.35)
Ringmain distribution pipeline costs	(0.08)	(0.30)
Netback	**2.11**	**3.01**

Netbacks were lower in 2005 due to the commencement of sales to the power sector at considerably lower prices than that achieved for sales to the industrial sector. However, higher sales 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:

(*Figures in* US$'000)	Year ended 31 December 2005	Period ended 31 December 2004
Employee costs	846	216
Stock based compensation	383	381
Travel & accommodation	181	45
Communications	75	24
Office	412	75
Consultants	626	175
Insurance	166	72
Auditing & taxation	97	34
Depreciation	93	–
Reporting, regulatory and corporate finance	173	34
Other corporate	434	71
Directors' fees	69	14
	3,555	**1,141**
Less: capitalised pre-operating expenses	–	(87)
Total general and administrative expenses	**3,555**	**1,054**

G&A averaged approximately US$0.29 million per month (2004: US$0.26 million) (including the stock-based compensation and depreciation). The increase in G&A primarily resulted from an increase in staff numbers and pay rates for both employees and consultants in a tight labour market.

US$619,000 of consultant costs and professional fees that are directly related to the development of the natural gas properties were capitalized during the year.

The G&A per mcf fell significantly to US$1.40/mcf (2004: US$8.74/mcf) as a large proportion of the G&A is relatively fixed in nature and therefore declines as volumes increase.

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. The monthly charge was revised to US$32,000 in 2005 to reflect the likelihood that more beneficiaries will take up options granted to them. The revised amount will continue to be charged to the income statement until all options have vested in September 2006.

Taxes

Under the terms of the PSA, the Company is liable to Tanzanian income tax. However, this is recovered from TPDC by deducting an amount up from TPDC's profit share. On receipt of any Profit Gas under the PSA, the Company's revenue will be grossed for associated income tax. The Company and TPDC are seeking clarification from the Commissioner of Taxes as to how it intends to treat the capitalised expenses for tax purposes as there appears to be some conflict between the language of the PSA and the Tanzanian Income Tax Act 2004. The principal difference is whether the capitalised costs will be written off (PSA language) or capitalised over a few years (per the Income Tax Act 2004). US$59,000 is payable as income tax for the year ended 31 December 2005 if the Commissioner of Taxes follows the Income Taxes Act 2004, but no tax is payable if it is determined that there should be an acceleration in the write off of the capitalised expenses.

As at 31 December 2005 there were temporary differences between the carrying value of the assets and liabilities for financial reporting purposes and the amounts used for taxation purposes under the Income Tax Act 2004. Applying the 30% Tanzanian tax rate, the Company has recognised a deferred tax liability of US$506,000. This tax has no impact on cash flow until it becomes a current income tax at which point the tax is paid to the Commissioner of Taxes and recovered from TPDC.

Additional Profits Tax

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

The Company provides for APT by forecasting the total APT payable as a proportion of the forecast Profit Gas over the term of PSA licence. As at 31 December 2005, the effective APT rate was calculated to be 18%. Accordingly, US$80,000 has been netted against revenue for the year ended 31 December 2005.

As at 31 December 2005, there were un-recovered costs of US$11.6 million. Management does not anticipate that any APT will be payable in 2006 as the forecast revenues will not be sufficient to cover the un-recovered costs brought forward as inflated by 25% plus the percentage change in the United States Industrial Goods Producer Price Index and the forecast expenditures for 2006. The actual APT that will be paid is dependent on the achieved value of the Additional Gas sales and the quantum and timing of the operating costs and capital expenditure programme.

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

Depletion and Depreciation

The Natural Gas Properties are depleted using the unit of production method based on the production for the period as a percentage of the total future production from the Songo Songo proven reserves. As at 31 December 2005, the proven reserves as evaluated by the independent reservoir engineers, McDaniel & Associates Consultants Ltd. ("McDaniel") were 240.6 bcf (2004: 171.2 bcf) on a life of licence basis. This leads to a depletion charge of US$0.33/mcf in 2005 (2004: US$0.29/mcf).

Non-Natural Gas Properties are depreciated as follows:

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

Recoverable Costs

As at 31 December 2005, the Company had US$11.6 million (31 December 2004: US$6.3 million) of costs that are recoverable out of 75% of the future Net Revenues.

Carrying Value of Assets

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

Cash Flow

Cash flows from operations were US$2.1 million for the year ended 31 December 2005 (2004: US$0.3 million). The components of the Company's cash flow are as follows:

(*Figures in* US$'000)	Year ended 31 December 2005	Period ended 31 December 2004
Profit/(loss) for the period	953	(727)
Adjustment for non cash items	1,187	416
Cash flows from operations	**2,140**	(311)
Working capital adjustments	291	1,278
Natural gas properties and other equipment expenditure	(5,648)	(924)
Net proceeds from rights issue and exercise of options	4,375	–
Net increase in cash and cash equivalent	**1,158**	**43**

The US$1.2 million increase in the net cash and cash equivalent during the year was primarily due to the net receipt of US$4.4 million from the rights issue and increase in sales.

Capital Expenditures

Capital expenditures amounted to US$5.6 million during the year (2004: US$0.9 million). The capital expenditure may be analysed as follows:

(*Figures in* US$'000)	Year ended 31 December 2005	Period ended 31 December 2004
Geological and geophysical	2,757	147
Pipelines and infrastructure	2,090	480
Power development	789	–
Other equipment	12	297
	5,648	**924**

During 2005, the Company conducted seismic work on the Songo Songo licence area and on the Nyuni farm-in licence acreage. The US$2.8 million seismic work consisted of the acquisition, processing and interpretation of: 917 kilometers of new 2D seismic utilising the Geomariner survey vessel as well as the reprocessing of 569 kilometers of the old vintage 2 D seismic.

The 917 kilometers of new seismic was acquired in the following areas:

	Kilometers
Discovery Blocks	212
Adjoining Blocks	377
Nyuni A area (farm-in area)	328
	917

Under the terms of the Songo Songo PSA, the seismic associated with the Discovery Blocks and Adjoining Blocks is recoverable out of the revenues generated under the Songo Songo PSA. In contrast, the costs associated with the Nyuni A area are only recoverable out of revenues generated on the Nyuni PSA and provided the Company meets all its farm-in obligations.

In the event that Company does not retain the Adjoining Blocks the Company will continue to recover the seismic and other exploration costs that it has incurred on the Adjoining Blocks (circa US$0.5 million) out of the Songo Songo PSA revenues.

The Company completed a 8.6 kilometer pipeline to Karibu Textile Mills Limited at a cost of US$1.0 million. Another 3.6 kilometer spur to Lakhani Industries Limited Textile and Murzah Oil Mills Limited which started during the year was completed after the year end. US$900,000 has been capitalised at the year end to reflect the value of the completed work as a proportion of the total contract price. The total cost of the Lakhani-Murzah pipeline is estimated at US$1.1million.

Power development includes the costs of installing meters (US$0.2 million) and the legal and other consultancy costs associated with the negotiation and development of the contract (US$0.6 million) for the supply of gas to the Ubungo Power Plant that is owned and operated by Songas Limited.

Working Capital

Working capital as at 31 December 2005 was US$2.2 million (31 December 2004: US$1.2 million) and may be analysed as follows:

(*Figures in* US$'000)	**31 December 2005**	31 December 2004
Cash and cash equivalents	3,198	2,040
Trade and other receivables	2,862	441
	6,060	**2,481**
Total current liabilities	3,849	1,265
Working capital	**2,211**	**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 2005, US$629,000 (31 December 2004: US$92,000) was owed to TPDC.
- 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 2005 the Company owed Songas US$420,000 (31 December 2004: US$97,000) for the tariff. The amount due at the year end represents an outstanding balance of two months, which matches the time that Songas is taking to pay for the Additional Gas used at the Ubungo Power Plant.

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

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

Under the contract terms with the industrial customers, the Additional Gas payments must be received within 30 days of the month end. As at 31 December 2005, US$1.3 million was due for the month of November and December (including VAT) from the industrial customers. This amount has been subsequently received. Trade and other receivables also includes an amount of US$1.1 million due from Songas Limited for the supply of Additional Gas to the Ubungo Power Plant. The contract with Songas Limited accounted for 34% of the Company's operating revenue in 2005. Songas Limited's financial security is heavily reliant on the payment of capacity and energy charges by the electricity utility, TANESCO. TANESCO is currently experiencing financial difficulties principally caused by low rains and the consequential loss of the hydro electricity generation. As a result, TANESCO is dependent on the Government of Tanzania for day to day funding. Whilst some payments have been delayed, the Company collected all amounts due from Songas Limited as of 31 December 2005. The level of receivables will be closely monitored to minimise any potential default by any of the Company's customers.

The current liabilities increased in 2005 primarily as a result of the increase in the amount of profit share due to TPDC and tariff to Songas Limited resulting from the increase in Additional Gas sales. Current liabilities also included an amount of US$652,000 for seismic work, an accrual of US$542,000 in respect of the completed elements of the Lakhani-Murzah pipeline and accruals for staff bonus, taxes and other operating costs.

Management forecasts that the Company will be able to meet its 2006 capital expenditure programme through the use of existing funds, self - generated cash flows and the raising of equity. In addition, the Company has no bank borrowings and there is scope for utilising debt funding once the 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 31 December 2005 and may be analysed as follows:

Number of shares ('000)	**31 December 2005**	31 December 2004
SHARES OUTSTANDING		
Class A shares	1,751	1,751
Class B shares	21,513	19,386
	23,264	**21,137**
CONVERTIBLE SECURITIES		
Options	1,987	2,000
Fully diluted Class A and Class B shares	**25,251**	**23,137**
WEIGHTED AVERAGE		
Class A and Class B shares	22,903	21,137
Options	1,987	2,000
Weighted average diluted Class A and Class B shares	**24,890**	**23,137**

After the year end, a further 100,000 Class B shares were issued further to the exercise of 100,000 options.

Stock Based Compensation

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

2,000,000 options were issued to certain Directors and Officers on 1 September 2004 at a price of Cdn$1 per option. During Q1, 12,600 options were exercised at a price of Cdn$1 per option. A total of 1,987,400 options remained outstanding at the year end.

Contractual Obligations and Committed Capital Investment

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

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

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

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

The Company acquired 377 kilometers of 2D seismic on the Adjoining Blocks during October 2005 using the Geomariner survey vessel and the interpretation of the seismic revealed a small accumulation ("Lead A"). However, management has not yet committed to the drilling of a well on Lead A. The MEM has indicated that provided the Company commits to drill a well by 30 April 2006 and drills it by 11 April 2007, it may retain the Adjoining Blocks. The Company is currently evaluating this offer. In the event that the Company relinquishes the Adjoining Blocks, there is no impact on the rights under the PSA to the Discovery Blocks and hence the potential of the existing field and the Songo Songo West prospect.

During the year, the Company commenced construction of a 3.6 kilometer pipeline spur to two new customers, Lakhani Industries Limited Textile and Murzah Oil Mills Limited at a cost of US$1.1 million. The work was completed subsequent to the year end. The Company is committed to make monthly payments to a Contractor for the remaining balance of US$740,000 (inclusive of local taxes) as at the year end.

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 in Area A. 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 the Company elects to drill, it will pay either 42% to earn a 35% interest in Area A or 64% to earn a 50% interest. The cost of any Nyuni well can only be recovered out of future revenues from the Nyuni PSA.

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

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

Contingent Liabilities

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

Post Balance Sheet Events

There are no Post Balance Sheet Events other than those disclosed under 'Contractual Obligations and Committed Capital Investment' and 'Contingent Liabilities' above.

Off-Balance Sheet Transactions

As at 31 December 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$102,000 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.

There have been no transactions undertaken with related parties during the year ended 31 December 2005.

Summary Quarterly Results

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

	2005				2004	
(Figures in US$'000 except where otherwise stated)	Q4	Q3	Q2	Q1	Q4	Q3
FINANCIAL						
Revenue	**2,741**	2,156	512	350	391	50
Profit/(loss) after taxation	**396**	785	(275)	(518)	(643)	(84)
Netback (US$/mcf)	**2.51**	1.68	3.86	3.24	3.00	3.51
Working Capital	**2,211**	3,559	2,789	4,895	1,216	2,289
Shareholders’ Equity	**16,662**	16,096	15,240	15,444	11,516	11,857
Profit/(loss) per share – basic	**0.02**	0.03	(0.01)	(0.02)	(0.03)	(0.04)
Profit/(loss) per share – diluted	**0.02**	0.03	(0.01)	(0.02)	(0.03)	(0.04)
CAPITAL EXPENDITURE						
Geological and geophysical	**2,001**	148	520	88	137	10
Pipeline and infrastructure	**868**	110	902	210	479	1
Power development	**34**	224	531	–	–	–
Other equipment & business development	**(1)**	3	5	5	150	148
OPERATING						
Additional Gas sold (mmscf) - Industrial	**299.3**	260.7	119.7	96.9	107.1	13.5
Additional Gas sold (mmscf) - Power	**766.1**	905.4	–	–	–	–
Average price per mcf (US$) - Industrial	**7.86**	7.26	6.19	5.23	5.31	5.41
Average price per mcf (US$) - Power	**2.15**	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.

The principal developments in Q4 were as follows:

- Successfully completed the acquisition of 917 kilometers of 2D seismic with limited downtime for customs clearance and standby time.
- Processed and interpreted the seismic data and identified the principal exploration prospect 2 kilometers west of the existing Songo Songo field with a most likely Gas Initially in Place of 600 bcf if the drilling program is successful.
- Achieved average Additional Gas sales of 3.3 mmscf/d to the industrial sector at an average price of US$7.86/mcf. This was despite the industrial sector entering a seasonally low period of production that will continue through to March 2006.
- Signed contracts with and commenced the construction of a 3.6 kilometer pipeline to Lakhani Industries Limited Textile and Murzah Oil Mills Limited. These customers will commence gas consumption in Q2 2006 at an estimated rate of 0.5 mmscf/d. This pipeline is also the first step (an additional 8 kilometers of pipeline is required) in closing the existing pipeline so that gas can be fed into it from two separate pressure reduction stations so improving security of supply and increasing its capacity.

- Achieved average Additional Gas sales of 8.3 mmscf/d to the power sector at an average price of US$2.15/mcf. There was no significant downtime at the Ubungo Power Plant and accordingly the Company did not have to discount the power price for low 'availability' of the six turbines and the volumes were strong.
- The netbacks per mcf benefited from the higher achieved prices both for the industrial and the power sector.
- Incurred capital expenditure of US$2.9 million primarily on the seismic acquisition, its processing and interpretation (US$2.0 million) and on the construction of the 3.6 kilometer pipeline to Lakhani Industries Limited Textile and Murzah Oil Mills Limited.

Operating Hazards and Uninsured Risks

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

Foreign Operations

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

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

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

Additional Financing

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

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

Industry Conditions

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

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

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

Additional Gas

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

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

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

Replacement of Reserves

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

Asset Concentration

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

Environmental and Other Regulations

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

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

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

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

Volatility of Oil and Gas Prices and Markets

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

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

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

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

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

Uncertainties in Estimating Reserves and Future Net Cash Flows

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

Title to Properties

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

Acquisition Risks

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

Reliance on Key Personnel

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

Controlling Shareholder

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

Financial Statements

Management's Report to Shareholders

The accompanying Consolidated Financial Statements of EastCoast Energy Corporation are the responsibility of the Directors. The financial and operating information presented in this Annual Report is consistent with that shown in the Consolidated Financial Statements.

The Consolidated Financial Statements have been prepared by Management, on behalf of the Board, in accordance with the accounting policies disclosed in the Notes to the Consolidated Financial Statements. Where necessary, Management has made informed judgments and estimates in accounting for transactions which were not complete at the balance sheet date. In the opinion of Management, the Consolidated Financial Statements have been prepared within acceptable limits of materiality and are in accordance with International Financial Reporting Standards appropriate in the circumstances.

Management, with the participation of the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company's disclosure controls and procedures and has concluded that such disclosure controls and procedures are effective.

Management maintains appropriate systems of internal controls. Policies and procedures are designed to give reasonable assurance that transactions are properly authorised, assets are safeguarded and financial records are properly maintained to provide reliable information for the preparation of financial statements. An independent firm of Chartered Accountants, as appointed by the Shareholders, examines the Consolidated Financial Statements in accordance with International Financial Reporting Standards and provides an independent professional opinion.

The Board of Directors carries out its responsibility for the financial reporting and internal controls principally through an Audit Committee and a Reserves Committee. The committees have met with external auditors and Management in order to determine if Management has fulfilled its responsibilities in the preparation of the Consolidated Financial Statements. The Consolidated Financial Statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

P. R. Clutterbuck
President & Chief Executive Officer

Nigel Friend
Chief Financial Officer

Auditors' Report

We have audited the Consolidated Balance Sheet of EastCoast Energy Corporation as at 31 December 2005 and 2004 and the Consolidated Statements of Income, Changes in Shareholders' Equity and Cash Flows for the year ended 31 December 2005 and for the period from 31 August 2004 to 31 December 2004. These Consolidated Financial Statements are the responsibility of the Company's Directors. Our responsibility is to express an opinion on these Consolidated Financial Statements based on our audits.

We conducted our audits in accordance with International and Canadian Standards on Auditing. Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the Consolidated Financial Statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the Consolidated Financial Statements. An audit also includes assessing the accounting principles used and significant estimates made by the Directors, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, these Consolidated Financial Statements give a true and fair view of the financial position of the Company as at 31 December 2005 and 2004 and the results of its operations and its cash flows for the year ended 31 December 2005 and for the period from 31 August 2004 to 31 December 2004 in accordance with International Financial Reporting Standards.

KPMG LLP

Calgary, Canada
25 April 2005

COMMENTS BY AUDITORS FOR CANADIAN READERS ON INTERNATIONAL – CANADIAN DIFFERENCES

Canadian reporting standards may differ from International Standards on Auditing in the form and content of the auditors' report, depending on the circumstances. However, had this auditors' report been prepared in accordance with Canadian reporting standards, there would be no material differences in the form and content of this auditors' report. Furthermore, an auditors' report prepared in accordance with Canadian standards on the aforementioned consolidated financial statements would not contain a qualification of opinion.

KPMG LLP

Calgary, Canada
25 April 2005

Consolidated Income Statement

(thousands of US dollars except per share amounts)	Note	Year ended 31 December 2005	Period ended 31 December 2004
Revenue	2	**5,759**	441
Cost of sales			
Production and distribution expenses		**(495)**	(78)
Depletion expense	7	**(818)**	(35)
Gross profit		**4,446**	328
Other income		**64**	7
Administrative expenses		**(3,555)**	(1,054)
Foreign exchange losses		**(2)**	(8)
Profit/(loss) before taxation		**953**	(727)
Taxation	4	**(565)**	–
Profit/(loss) after taxation		**388**	(727)
Profit/(loss) per share	11		
Basic (US$)		**0.02**	(0.03)
Diluted (US$)		**0.02**	(0.03)

See accompanying notes to the consolidated financial statements.

Consolidated Balance Sheet

(thousands of US dollars)	Note	As at 31 December 2005	As at 31 December 2004
ASSETS			
Current assets			
Cash and cash equivalents	5	**3,198**	2,040
Trade and other receivables	6	**2,862**	441
		6,060	2,481
Natural gas properties and other equipment	7	**15,037**	10,300
		21,097	12,781
LIABILITIES			
Current liabilities			
Trade and other payables	8	**3,849**	1,265
Non current liabilities			
Deferred tax	4	**506**	–
Deferred additional profits tax	4	**80**	–
SHAREHOLDERS' EQUITY			
Capital stock	10	**16,237**	11,862
Capital reserve		**764**	381
Accumulated Loss		**(339)**	(727)
		16,662	11,516
		21,097	12,781

See accompanying notes to the consolidated financial statements.

The consolidated financial statements were approved by the Board on 25 April 2005.

John Patterson
Director

Nigel Friend
Director

Consolidated Statement of Cash Flows

(thousands of US dollars)	Year ended 31 December 2005	Period ended 31 December 2004
CASH FLOWS FROM OPERATING ACTIVITIES		
Profit/(loss) before tax	**953**	(727)
Adjustments for:		
Depletion and depreciation	**911**	35
Stock-based compensation	**383**	381
Other	**(107)**	–
Funds from operations before working capital changes	**2,140**	(311)
(Increase)/decrease in trade and other receivables	**(2,234)**	1,962
Increase/(decrease) in trade and other payables	**1,897**	(724)
Net cash flows from operating activities	**1,803**	927
CASH FLOWS USED IN INVESTING ACTIVITIES		
Acquisition of natural gas properties and other equipment	**(5,648)**	(924)
Increase in trade and other payables	**628**	40
Net cash used in investing activities	**(5,020)**	(884)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net proceeds from rights issue	**4,365**	–
Proceeds from exercise of options	**10**	–
Cash provided by financing activities	**4,375**	–
Increase in cash and cash equivalents	**1,158**	43
Cash and cash equivalents at the beginning of the period	**2,040**	1,997
Cash and cash equivalents at the end of the period	**3,198**	2,040

See accompanying notes to the consolidated financial statements.

Statement of Changes in Shareholders' Equity

(thousands of US dollars)	Capital stock	Capital reserve	Accumulated Loss	Total
Note	10			
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**
Rights issue net of share issue costs	4,365	–	–	**4,365**
Options exercised	10	–	–	**10**
Profit for the year	–	–	388	**388**
Stock-based compensation	–	383	–	**383**
Balance as at 31 December 2005	**16,237**	**764**	**(339)**	**16,662**

See accompanying notes to the consolidated financial statements.

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.

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 mmscf/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 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 as feedstock for specified turbines and kilns.

Gas sales in excess of the Protected Gas users' requirements is classified 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.

In addition, to its rights under the PSA, the Company has entered into a farm-in agreement with Ndovu Resources Limited, a subsidiary of Aminex plc, for licence acreage adjacent to the Songo Songo field.

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.

These principles may differ in certain respects from those in Canada. These differences are described in note 13.

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.

The following companies have been consolidated within the EastCoast financial statements:

Subsidiary	Registered	Holding
EastCoast Energy Corporation	British Virgin Islands	Parent Company
PAE PanAfrican Energy Corporation	Mauritius	100%
PanAfrican Energy Tanzania Limited	Jersey	100%

ii) Transactions eliminated upon consolidation

Inter-company balances and transactions, and any unrealised gains arising from inter-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) 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, 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 income. The carrying amounts are assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves exceed the carrying amount of the natural gas properties. When the carrying amount is not assessed as recoverable, an impairment loss is recognized to the extent that the carrying amount of the natural gas properties exceeds the sum of the discounted cash flows from the production of proved and probable reserves. The cash flows are estimated using expected future product prices and costs and discounted using a risk-free rate.

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.

e) 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. When 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.

f) Trade and other receivables

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

g) Cash and cash equivalents

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

h) 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 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.

i) 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.

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.

j) Revenue recognition, production sharing agreements and royalties

The Company recognises revenue from natural gas sales when title passes to a customer. The Company conducts operations jointly with the Tanzanian government and parastatal entities in accordance with production sharing agreements ("PSA"). 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 ("Cost Gas"). 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.

The Company is entitled to a share of production in excess of the Cost Gas ("Profit Gas").

Operating revenue represents the Company's share of Cost Gas and Profit Gas during the period, net of the transportation tariff.

k) Additional profits tax

Under the terms of the PSA, in the event that all costs have been recovered with an annual return of 25% plus the percentage change in the United States Industrial Goods Producer Price Index, an additional profits tax ("APT") is payable to the Government of Tanzania. This tax is considered to be a royalty and is netted against revenue. APT is provided by forecasting the total APT payable as a proportion of the forecast Profit Gas over the term of the PSA licence.

l) Taxation

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

The Company is liable for Tanzanian income tax, which is paid through the profit-sharing arrangements with TPDC. Where income tax is payable, revenue is grossed up for the tax recoverable under the PSA and the income tax shown as current tax.

Deferred tax is provided using the balance sheet 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.

m) Segmental reporting

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

n) Measurement uncertainty

The amounts recorded for depletion and depreciation of natural gas properties and the cost recovery ceiling test are based on estimates. These estimates include proven and probable reserves, production rates, natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect of changes in such estimates on the financial statements of future periods could be significant.

o) Depreciation

Depreciation for non-natural gas properties is charged to the income statement on a straight line basis over the estimated useful economic lives of each class of asset. The estimated useful lives are as follows:

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

2 Revenue

	Year ended 31 December 2005	Period ended 31 December 2004
Operating revenue	**5,652**	441
Gross-up for income tax	**187**	–
Deferred additional profits tax	**(80)**	–
Revenue	**5,759**	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(j).

The Company's total revenues for the year amounted to US$5,759,000 after adjusting the Company's operating revenue of US$5,652,000 by:

i) US$187,000 for income tax. The Company is liable for income tax in Tanzania, but the income tax is recoverable out of TPDC's Profit Gas when the tax is payable. To account for this, revenues are grossed up for the income tax and the tax is shown separately;

ii) US$80,000 for the deferred effect of Additional Profits Tax. This tax is netted off revenue as a royalty.

3 Personnel expenses

The average number of employees during the year was 12 (2004: 10). The costs are as follows:

	Year ended 31 December 2005	Period ended 31 December 2004
Wages and salaries	**701**	169
Social security costs	**87**	25
Other statutory staff costs	**58**	22
	846	216
Capitalised pre-operating costs	**–**	(33)
	846	183

During 2004, the staff costs prior to the commencement of commercial production of Additional Gas on 18 September 2004 were capitalized.

4 Taxation

Under the terms of the Production Sharing Agreement with TPDC, the Company is liable for income tax in Tanzania at a corporate tax rate of 30%. However, where income tax is payable, the profit available to TPDC is reduced by this amount.

The Company and TPDC are seeking clarification from the Commissioner of Taxes in Tanzania as to how it intends to treat the capitalised expenses for current tax purposes due to conflicts in the language of the PSA and the Tanzanian Income Tax Act 2004. The principal difference is whether the capitalised costs will be written off (PSA language) or written down over a few years (per the Income Tax Act 2004). The reported income tax has assumed that capitalised costs are written down over a few years.

Under the terms of the Tanzanian Income Tax Act, the Company generated 2005 tax profits and accordingly is liable to pay income tax. This amount will be recovered from TPDC's profit share during 2006. In the event that it is deemed that the income tax liability will be determined in accordance with the terms of the PSA, the overall tax charge will remain the same, but there will be a re-allocation from current tax to deferred tax.

At December 31, 2005, there were temporary differences between the carrying value of the assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Accordingly a deferred tax liability has been recognized for the year ended 31 December 2005.

The tax charge may be analysed as follows:

	Year ended 31 December 2005	Period ended 31 December 2004
Current tax	**59**	–
Deferred tax	**506**	–
	565	–

Tax Rate Reconciliation

	Year ended 31 December 2005	Period ended 31 December 2004
Profit/(loss) before taxation	**953**	(727)
Provision for income tax calculated at the statutory rate	**286**	(218)
Add/(deduct) the tax effect of non-deductible income tax items:		
Other income	**(19)**	(3)
Administrative and operating expenses	**161**	43
Stock based compensation	**115**	114
Other	**82**	4
Reversal of previously unrecognised deferred tax asset	**(60)**	60
	565	–

The deferred income tax liability includes the following temporary differences:

	Year ended 31 December 2005	Period ended 31 December 2004
Differences between tax base and carrying value of natural gas properties	**506**	(60)

5 Cash and cash equivalents

	As at 31 December 2005	As at 31 December 2004
Cash and short term deposits	**3,198**	2,040

Included in the cash and cash equivalent are:

- US$103,000 advanced from Songas under the terms of the Operatorship Agreement to pay for the costs of operating the wells and gas processing plant.

– US$130,000 advanced from Lakhani Industries Limited and Murzah Oil Mills Limited as a deposit for their pipeline connection. This will be repaid once they have consumed in excess of US$200,000 and US$100,000 of Additional Gas each respectively.

6 Trade and other receivables due in less than one year

	As at 31 December 2005	As at 31 December 2004
Trade receivables	**2,419**	174
Prepayments	**150**	84
Other receivables	**293**	183
	2,862	441

7 Natural gas properties and other equipment

	Natural gas properties	Leasehold improvements	Computer equipment	Vehicles	Fixtures & fittings	Total
COSTS						
As at 1 January 2005	10,057	156	52	34	36	**10,335**
Additions	5,636	–	7	4	1	**5,648**
As at 31 December 2005	15,693	156	59	38	37	**15,983**
DEPLETION/DEPRECIATION						
As at 1 January 2005	35	–	–	–	–	35
Charge for the year	818	49	19	13	12	**911**
As at 31 December 2005	853	49	19	13	12	**946**
NET BOOK VALUES						
At 31 December 2005	**14,840**	**107**	**40**	**25**	**25**	**15,037**
At 31 December 2004	10,022	156	52	34	36	10,300

Included in the Natural Gas Properties as 31 December 2005, is US$0.5 million representing the costs of acquiring and processing 328 kilometers of seismic on the Nyuni 'A' area subject to the farm-in terms with a subsidiary of Aminex plc. In accordance with accounting policy 1 (d), this asset will not be depleted until it is determined whether or not proved reserves are attributable to the properties, or impairment occurs.

In determining the depletion charge, it is estimated by the independent reserve engineers that future development costs of US$ 69.6 million (2004: US$39.7 million) will be required to bring the total proved reserves to production.

US$0.6 million of consultant costs and professional fees that are directly related to the development of the natural gas properties were capitalized during the year.

8 Trade and other payables

	As at 31 December 2005	As at 31 December 2004
Trade payables	**1,930**	308
Accrued liabilities	**1,919**	957
	3,849	1,265

9 Financial instruments

The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in its operations.

Credit risk

The Company has a number of industrial customers and a short term contract with Songas Limited for the supply of gas to the Ubungo Power Plant. The contract with Songas Limited accounted for 34% of the Company's operating revenue during 2005 and US$1.1 million of the receivables at the year end. Songas Limited's financial security is heavily reliant on the payment of capacity and energy charges by the electricity utility, TANESCO. TANESCO is currently experiencing financial difficulties principally caused by the low rains and the consequential loss of the hydro electricity generation. As a result, TANESCO is dependent on the Government of Tanzania for day to day funding. Whilst some payments have been delayed, the Company collected all amounts due from Songas Limited and the industrial customers as of 31 December 2005.

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 year.

Fair values

Financial instruments of the Company carried on the balance sheet consist mainly of current assets and current liabilities. 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.

10 Capital stock

a) 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.

b) Changes in the capital stock of the Company were as follows:

	2005			2004		
Thousands of shares or US$	Authorised	Issued	Valuation	Authorised	Issued	Valuation
Class A shares						
As at 31 December	**50,000**	**1,751**	**983**	50,000	1,751	983
Class B shares						
As at the beginning of the period	**50,000**	**19,386**	**10,879**	50,000	19,386	10,879
Issued, net of share issue costs	**–**	**2,114**	**4,365**	–	–	–
Options exercised	**–**	**13**	**10**	–	–	–
As at 31 December	**50,000**	**21,513**	**15,254**	50,000	19,386	10,879
Total Class A & B shares at 31 December	**100,000**	**23,264**	**16,237**	100,000	21,137	11,862

On 4 March 2005, the Company issued 2,113,744 Class B shares at Cdn$2.60 per share. Net proceeds of US$4.4 million were raised for the Company.

Under the term of the rights issue:

- each holder of Class B shares was entitled to receive one right for each Class B share held and ten rights entitled the holder to subscribe for one Class B share at a price of Cdn$2.60; and

- each holder of Class A shares was entitled to receive one right for each Class A share held and ten rights entitled the holder to subscribe for one Class B share at a price of Cdn$2.60.

The subscription price of Cdn$2.60 represented a 15% discount to the closing trading price of the Class B shares on 19 November, 2004.

Stock-based compensation plan

On 1 September 2004, 2,000,000 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 2005, 1,333,332 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 of option valuation, IFRS 2. The fair value of each option was estimated as at the grant date 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%.

The fair value of the options was US$ 1,051,000 with a compensation expense of US$383,000 (2004: US$381,000) for the year ended 31 December 2005. The total remaining to be expensed at 31 December 2005 amounted to US$287,000.

During the year, 12,600 options were exercised at a price of Cdn$1 per option at an average share price of Cdn$3.5. A total of 1,987,400 options remain outstanding.

11 Profit/loss per share

The calculation of basic profit per share is based on the net profit attributable to ordinary shareholders of US$388,000 (2004: loss of US$727,000) and a weighted average number of ordinary shares outstanding during the period of 22,902,699 (2004: 21,137,439 shares).

In computing the diluted earnings per share, the dilutive effect of the options were 1,987,400 shares. These were added to the weighted average number of common shares outstanding during the year ended 31 December, 2005. No adjustments were required to reported earnings from operations in computing diluted per share amounts.

12 Contingent liabilities

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

13 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.

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

	2005		2004 restated	
	IAS	CDN	IAS	CDN
Current assets	6,060	6,060	2,481	2,481
Natural Gas Properties and other equipment	15,037	16,852	10,300	12,151
	21,097	**22,912**	**12,781**	**14,632**
Current liabilities	3,849	3,849	1,265	1,265
Non current liabilities	586	2,385	–	1,851
Capital Stock	16,237	16,237	11,862	11,862
Reserves	425	441	(346)	(346)
	21,097	**22,912**	**12,781**	**14,632**

The adjustment has no material impact on the profit and loss account for the period ended 31 December 2004 and the year ended 31 December 2005.

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

14 Operating leases

Non-cancellable operating lease rentals are payable as follows:

	As at 31 December 2005	As at 31 December 2004
Less than one year	**92**	92
Between one and five years	**107**	199
	199	291

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

15 Post balance sheet events

There are no Post Balance Sheet Events other than those disclosed under ‘Contractual Obligations and Committed Capital Investment’ and ‘Contingent Liabilities’.

16 Contractual obligations and committed capital investment

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 has this right and may require security for larger volumes.

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

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

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

The Company acquired 377 kms of 2D seismic on the licence acreage during October 2005 and the interpretation of the seismic revealed a small accumulation ("Lead A"). However, management has not yet committed to the drilling of a well on Lead A. The MEM has indicated that provided the Company commits to drill a well by 30 April 2006 and drills it by 11 April 2007, it may retain the Adjoining Blocks. The Company is currently evaluating this offer. In the event that the Company relinquishes the Adjoining Blocks, there is no impact on the rights under the PSA to the Discovery Blocks and hence the potential of the existing field and Songo Songo West.

During the year, the Company commenced construction of a 3.6 kilometer pipeline spur to two new customers, Lakhani Industries Limited Textile and Murzah Oil Mills Limited at a cost of US$1.1million. The work was completed subsequent to the year end. The Company is committed to make monthly payments to a contractor for the remaining balance of US$740,000 (inclusive of local taxes) as at the year end.

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. 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 the Company elects to drill, it will pay either 42% to earn a 35% interest in Area A or 64% to earn a 50% interest. The cost of any Nyuni well can only be recovered out of future revenues from the Nyuni PSA.

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

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

17 Directors and officers emoluments

USD'000 *except no. of share options*	Year	Base compensation	Bonus	Other compensation	Total	Share options
DIRECTORS						
W. David Lyons (i)	**2005**	**21**	**–**	**–**	**21**	**1,000,000**
Chairman	2004	4	–	–	4	1,000,000
Peter R. Clutterbuck (i)	**2005**	**313**	**60**	**–**	**373**	**400,000**
President and CEO	2004	89	–	–	89	400,000
Nigel A. Friend (i)	**2005**	**220**	**43**	**–**	**263**	**200,000**
Vice President and CFO	2004	80	–	–	80	200,000
John Patterson (i)	**2005**	**19**	**–**	**–**	**19**	**50,000**
Non Executive Director	2004	7	–	–	7	50,000
Robert Spence (i)	**2005**	**18**	**–**	**–**	**18**	**50,000**
Non Executive Director	2004	6	–	–	6	50,000
OTHER						
Pierre Raillard (ii)	**2005**	**133**	**45**	**–**	**178**	**200,000**
Vice President Operations	2004	29	13	6	48	200,000

(i) *The 'Base compensation' 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.*

18 Comparative balance sheet

W. David Lyons is the Chairman and controlling shareholder of both PanOcean and EastCoast. The Company was spun off from PanOcean Energy Corporation ("PanOcean") through a Scheme of Arrangement on 31 August 2004. 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.

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

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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Jersey

Peter R. Clutterbuck
President & Chief
Executive Officer
Haslemere
United Kingdom

Nigel A. Friend
Chief Financial Officer
London
United Kingdom

John Patterson
Non-Executive Director
Nanoose Bay
Canada

Robert K. Spence
Non-Executive Director
Dar es Salaam
Tanzania

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Pierre Raillard
Vice President
Operations

David W. Ross
Company Secretary

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& Palmer LLP
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TRANSFER AGENT

CIBC Mellon Trust Company
Toronto, Montreal
and Calgary,
Canada

EASTCOAST Energy

www.eastcoast-energy.com