Discovery
Leadership
Growth

ANTRIM
ENERGY INC.

Annual Report 2004

Corporate Profile

Antrim Energy Inc. is an oil and gas exploration and production company. Antrim's production operations are centred in Argentina and its high impact oil and gas exploration is focused in the United Kingdom.

Antrim's objective is to create significant wealth for its investors through the discovery, production and sale of oil and gas. Strong revenue generation coupled with strategic partnerships ensure that the Company maintains financial and operational stability.

Publicly listed in 1999, Antrim has successfully emerged as a leadership company and has demonstrated that smaller companies can successfully invest in global high impact oil and gas exploration.

Antrim is based in Canada with offices in Argentina and the United Kingdom. The Company is listed on the senior Toronto Stock Exchange under the symbol "AEN" and on the London Stock Exchange's Alternative Investment Market under the symbol "AEY".

Contents

AGM The Annual and Special Meeting of Antrim shareholders will be held at 3 pm on Wednesday, June 1, 2005 at the Calgary Petroleum Club (319 – 5 Avenue SW Calgary Alberta).

Discovery Leadership Growth

Highlights

2003 - 2004

- 21% increase in oil production
- 34% increase in gross revenue
- 32% increase in net back
- 43% increase in capital expenditure
- 54% increase in proved producing reserves
- 32% decrease in operating costs

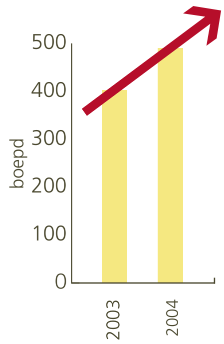
PRODUCTION GROWTH FOCUSED ON ARGENTINA

- Workover successes in the Puesto Guardian Field, Argentina
- Important acquisition in Tierra del Fuego, Argentina*

HIGH IMPACT DRILLING FOCUSED ON UK NORTH SEA

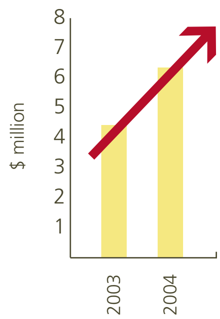
- New North Sea exploration licences acquired
- Two exploration wells to be drilled in the North Sea

* *Completed in February 2005*



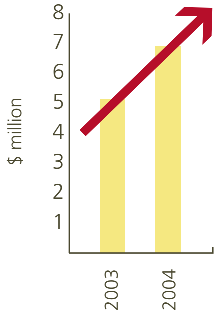
PRODUCTION

Antrim's daily oil production increased substantially over the previous year. The additional production acquired through the purchase of oil and gas fields in Tierra del Fuego, Argentina, and completed early in 2005, is not represented in these figures.



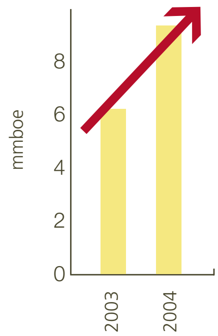
CAPITAL EXPENDITURE

Antrim's capital expenditure in 2004, primarily drilling and land acquisition costs increased 43% over the previous year, reflecting the Company's strategy of increasing investment in high impact exploration.



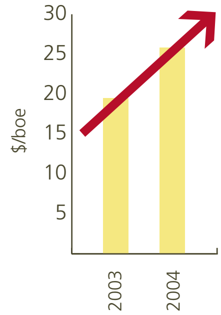
GROSS REVENUE

Gross revenue from oil and gas sales increased 34% over the previous year primarily as a result of increased oil production. Antrim expects to record further gains in revenue generation in 2005.



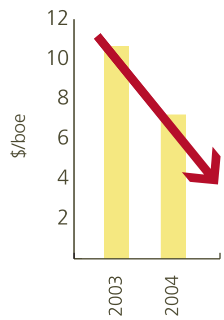
RESERVES

Antrim's "proved producing" oil and gas reserves increased significantly (54%) over the previous year. The substantial reserves acquired in early 2005 through the purchase of oil and gas fields in Tierra del Fuego, Argentina, are not represented in these figures.



NET BACK

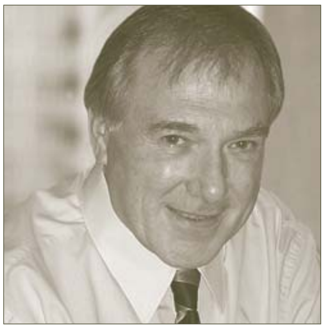
Higher commodity prices and lower per unit operating costs resulted in Antrim realizing a 32% increase in netback on a "per barrel" basis over the previous year.



OPERATING COSTS

Increased oil production, low variable costs and growing efficiency in Antrim's field operations have resulted in much lower operating costs measured on a "per barrel" basis over the previous year.

Letter to Shareholders



Dr. Gerry Orbell, Chairman

Stephen Greer, President and Chief Executive Officer

OVERVIEW

In 2004, Antrim Energy Inc. significantly increased oil and gas production and recorded a corresponding increase in revenues from oil and gas operations. The Company developed its exploration properties through seismic and drilling and substantially reduced its corporate risk profile by completing a series of strategic farm-out agreements. The farm-out agreements shield Antrim from the large capital costs of frontier exploration drilling while retaining the potential high impact on share value that results from successful drilling.

In Argentina, Antrim increased its oil production from the Puesto Guardian property by 21% over 2003. Subsequent to the year end, Antrim added further production gains through the acquisition of 613 barrels of oil equivalent (BOE) per day in crude oil, gas and gas liquids production in Tierra del Fuego. At the time of writing, Antrim's Argentine net-interest production of 1,100 boed represented a 175% gain compared to output at the end of 2003.

In the UK North Sea, Antrim consolidated its position in the prospective but relatively low risk exploration licence in the East Shetland Basin Block 211/22a. Subsequent to year-end, the Company farmed out an interest in the northern and western portion of Block 211/22a to a partner who will pay 100% of the costs of an exploration well on the "Clachnaben prospect" in 2005.

Antrim retains a 21% working interest in the Clachnaben well and has increased its holding to 79% in the lower-risk eastern portion of Block 211/22a that contains a 5,600 barrels per day discovery made in 1984.

The Company's risk profile was further improved by farming out an interest in the Southern Gas Basin exploration Blocks 42/21 & 22. In return for a well to be drilled in 42/21, Antrim has retained shareholders' exposure to over 100 Bcf (net) at no future cost to the Company.

The gross cost of the two planned exploration wells is estimated to exceed $25 million. Pursuant to the drilling farm-out agreements, Antrim will pay none of those capital expenditures, while retaining a significant working interest should a discovery be made in either well.

On Australia's Indian Ocean NorthWest Shelf, Antrim farmed out its South Galapagos high risk offshore exploration well to a third party who paid 80% of the US$9 million capital cost of drilling.

These outcomes underscored Antrim's successful strategy of developing and increasing revenue from our low risk properties while lowering the financial exposure to high risk operations. This strategy also retains the positive and very high impact that is inherent in successful international oil and gas exploration. At the end of the year, the Company held $21 million cash to fund exploration, drilling and development, no debt, and a significantly expanded array of drilling choices.

AT THE END OF THE YEAR THIS SUCCESSFUL STRATEGY LEFT THE COMPANY WITH AN EXTREMELY STRONG BALANCE SHEET WITH $21 MILLION CASH AND NO DEBT.

ENTERING 2005 WITH A STRONG BALANCE SHEET AND CASH FOR EXPANSION, ANTRIM EXPECTS TO FURTHER INCREASE PRODUCTION AND TO PARTICIPATE IN AT LEAST TWO HIGH IMPACT EXPLORATION WELLS IN THE UK NORTH SEA.

2004 FINANCIAL AND OPERATING RESULTS

In the year ended December 31, 2004, Antrim posted a 34% increase in revenue and a corresponding increase in operating cash flow. This significant increase in the Company's operating resources was primarily attributable to the success of the workover program in Argentina, and to increased commodity prices. However, substantial investment in Antrim's exploration operations, including the acquisition of interests in the UK North Sea in preparation for drilling in 2005, resulted in the Company posting a loss for the year of $0.16 per share, compared to $0.15 in 2003.

In Argentina, the changes made to the Puesto Guardian joint venture in 2003 allowed the Company and its partner to embark on a low cost workover program in 2004. This resulted in a 21% increase in oil production compared to 2003. Results to date have been very encouraging, often resulting in payout from each well's new production within a month of each recompletion.

2005 OUTLOOK

In fiscal 2005, entering the year with a strong balance sheet and cash for expansion, Antrim expects to participate in its first wells in the UK North Sea. These wells will target prolific sandstone reservoirs in areas with significant previous oil discoveries and established production. The drilling prospects represent lower risk opportunities than previous exploration wells drilled by Antrim and, if successful, are expected to have a major impact on the value of the corporation.

The Company also expects to continue to build on the strong trend of production increases seen over the past several years in Argentina through successful enhancement of field operations, drilling and new production acquisitions. In the coming year, Antrim will shoot an extensive 3-D seismic program on the new Tierra del Fuego properties and use these results to start the 2005 Argentina drilling program.

ACKNOWLEDGEMENTS

We would like to thank our colleagues in the Company for their hard work and their commitment. We especially wish to thank Mr. Murray Sinclair for his past contribution to the Antrim Board and at the same time welcome Mr. Jim Perry to the Board. Dr. Gerry Orbell, our UK-resident Director was elected Chairman of the Antrim Board in February 2005.

Though relatively small in the world of global exploration and production companies, we continue to grow and we will continue to punch above our weight around the world. We appreciate the continued support our shareholders have shown for this vision.

[signed]

Dr. Gerry Orbell
Chairman

[signed]

Stephen Greer
President and
Chief Executive Officer

UK North Sea

Argentina

→

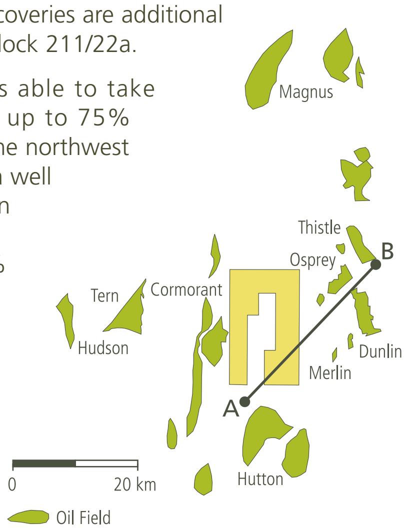
UK North Sea

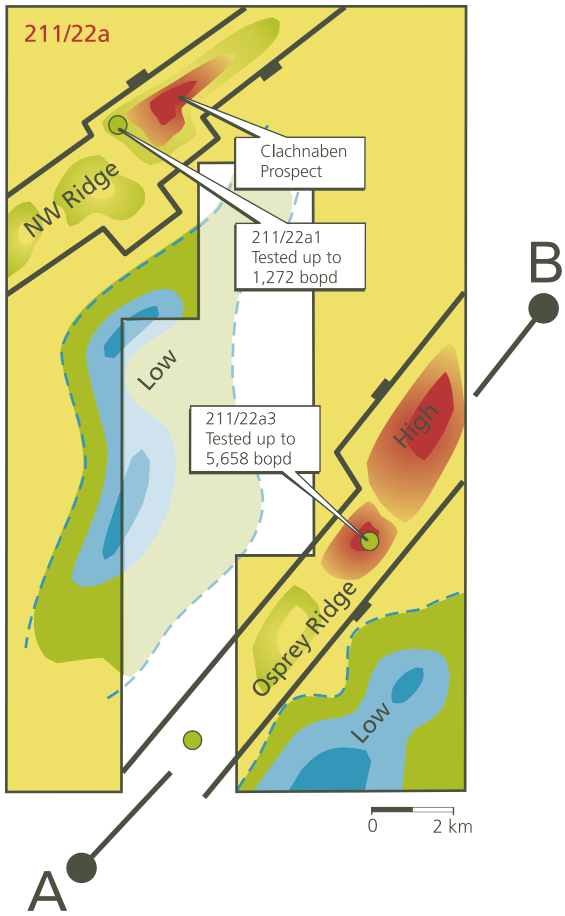
THE UNITED KINGDOM SECTOR OF THE NORTH SEA IS A GROWTH AREA FOR ANTRIM AND IS WHERE MUCH OF ANTRIM'S FUTURE HIGH IMPACT DRILLING WILL TAKE PLACE. IN 2004 ANTRIM ACQUIRED ADDITIONAL INTEREST AND NEW PROPERTIES IN THE SOUTHERN GAS BASIN AND IN THE EAST SHETLAND (OIL) BASIN.

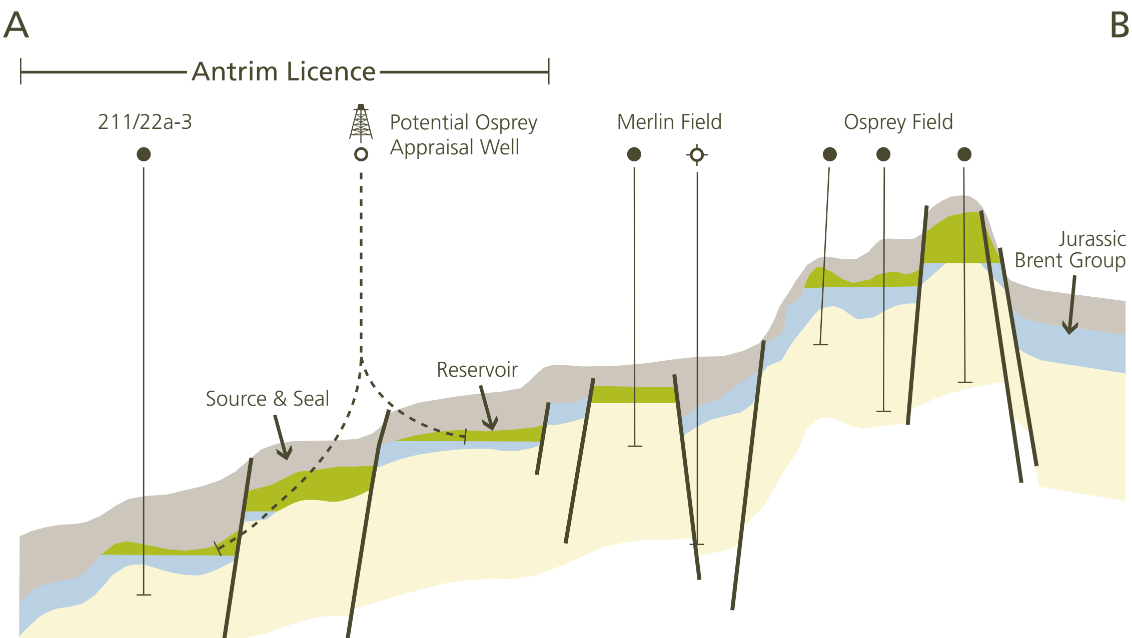
In 2004 Antrim acquired a 75% interest in a prospective licence (Block 211/22a) in the oil-rich East Shetland Basin of the UK North Sea.

There are two previously discovered oil accumulations on the Block. In the north, and on trend with Shell's North Cormorant Field (400 million barrels of recoverable oil), well 211/22a-1 flowed high quality oil at 1,250 bpd. The eastern part of Antrim's Block 211/22a lies over the Osprey Ridge, a geological "staircase" comprising discoveries such as 211/22a-3 which flowed at more than 5,600 bopd from the Brent Group and, further to the east, the Shell Osprey Field, which contained almost 100 million barrels of recoverable oil. Between these discoveries are additional undrilled prospects on Antrim's Block 211/22a.

In a series of deals, Antrim was able to take an initial 18% working interest up to 75% and then farm-out an interest in the northwest portion of the Block in return for a well drilled in 2005 (the Clachnaben prospect). As a result of this agreement, Antrim will retain 21% equity in the northern and western parts of the Block and increase its interest to 79% in the portion of the Block which contains the 5,600 bopd discovery.



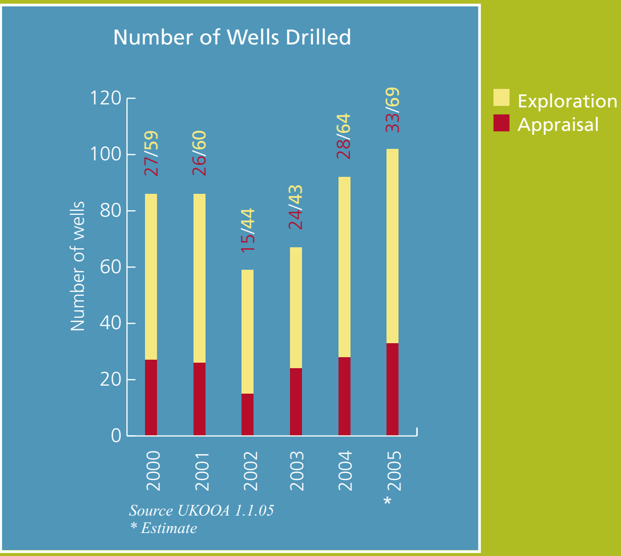




Schematic geological cross section along the Osprey Ridge

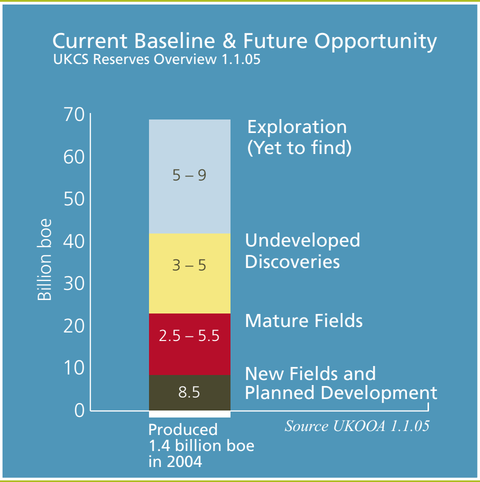
East Shetland
Basin
Ulster
Basin
Southern
Gas Basin
IRELAND
UK
London

During 2004 the pace of exploration and commercial activity increased significantly in the UK North Sea. Almost 200 companies are invested in this sector, many of which are relative newcomers encouraged by the government's Promote Licensing Rounds and its commitment to third party access to existing infrastructure. The main drivers were, however, the high oil prices obtained throughout the year and the high sales price of spot gas which rose to over $7.50 per mcf.

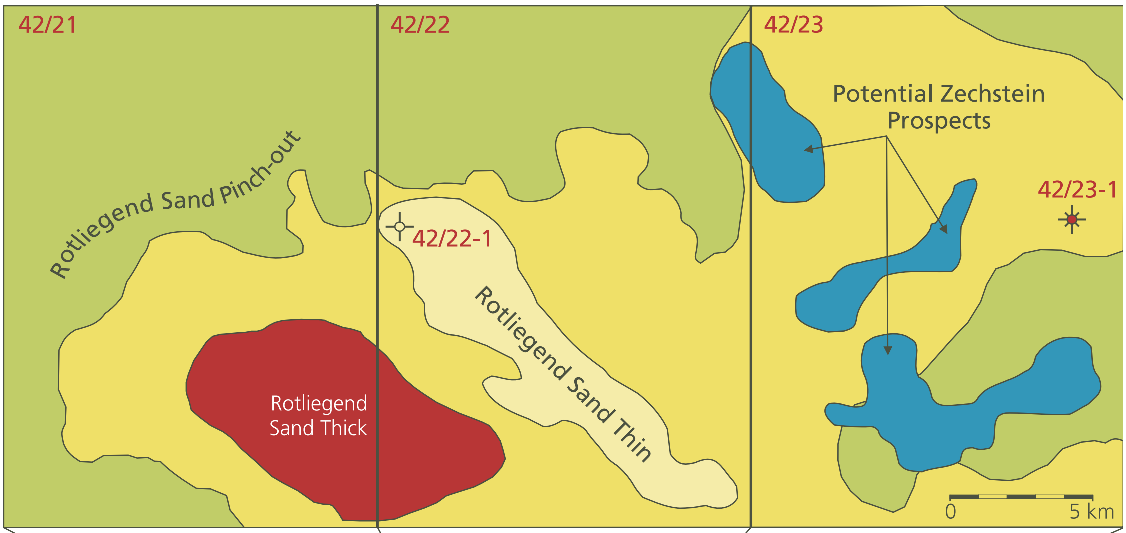


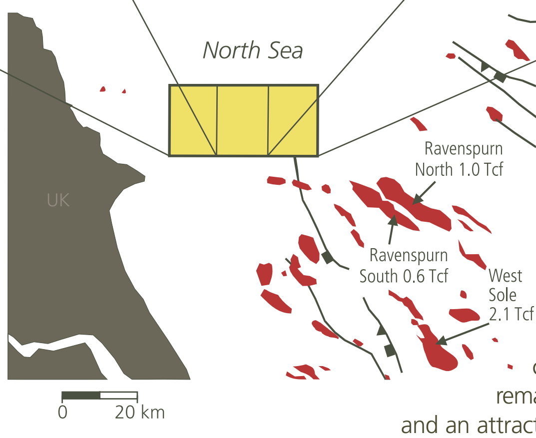
Large companies continued to put assets on the market as these no longer had material relevance to them; were outside their core areas; or were the subject of pressure to drill under the Fallow Acreage Program. This created a very active commercial environment for small companies in the UK and Antrim took full advantage of this situation.

Firstly, Antrim built strong equity positions in four blocks in the Southern Gas Basin and in the oil province of the Northern North Sea. We then farmed out our position to two different companies for two wells, together costing over $25 million, at no further cost to the Antrim shareholders. If successful, Antrim will add a significant volume of new oil and gas reserves which could have a major impact on the Company's value.



As a result of this increased activity, Antrim has opened an office in Leatherhead, near London. The UK will continue to be a major focus area for the Company and the Leatherhead staff will work on our current North Sea properties, have access to the large number of deals that are available throughout the UK, and provide easier access to the Antrim staff for our UK partners and shareholders.





In 2004, Antrim increased its 20% interest to 60% in Blocks 42/21 and 42/22 in the Southern Gas Basin and was subsequently awarded a 60% interest in the offsetting Block 42/23. In the fourth quarter, the Company signed an agreement with a US partner that is expected to drill an exploratory well to test Block 42/21 in 2005. If successful, the well, at no cost to Antrim, would test a structure capable of holding more than 1 Tcf of natural gas.

Natural gas is also the primary target on the Antrim-operated onshore South Larne Licence in Northern Ireland. In 2004 the Company made preparations for a seismic survey which began early in 2005. The South Larne Licence holds the potential for large natural gas reserves at shallow drilling depths close to pipelines and growing markets.

Today, natural gas accounts for 41% of the British economy's primary energy use (approximately 10 bcf/d). In 2005, domestic natural gas production will fall behind consumption for the first time in decades. In anticipation of this situation, gas will continue to command a high price and the UK will remain a strong and predictable gas market and an attractive exploratory target for Antrim.

As in 2004, Antrim will continue to seek out value opportunities in the North Sea for its shareholders. The Company expects to add to its 2005 North Sea drilling program through the formation of additional partnerships with strong Canadian- and UK-based companies.

Argentina

ARGENTINA IS ANTRIM'S MAJOR CENTRE OF OIL AND GAS PRODUCTION. THE COMPANY HAS DEMONSTRATED THE GROWTH POTENTIAL OF THE REGION BY INCREASING PRODUCTION YEAR OVER YEAR FROM ITS OIL FIELDS IN THE NORTHWEST BASIN AND THROUGH ITS (2005) ACQUISITION OF ADDITIONAL OIL AND GAS FIELDS IN THE SOUTHERN PROVINCE OF TIERRA DEL FUEGO.

Antrim's crude oil, natural gas and gas liquids production from Argentina increased dramatically in 2004, and again in the early part of 2005. Production increased from 382 barrels of oil per day in 2003 to 467 in 2004, and subsequent to the year-end Antrim's production increased to 1,100 boepd. The Company also recorded a dramatic increase in its reported oil and gas reserves in Argentina, from 1.7 mmboe proved and probable at end of 2003 to 4.5 mmboe at the begining of 2005. The gain was a result of successful re-completion operations in the NorthWest Basin and the acquisition negotiated in the fourth quarter of interests in several oil and gas fields in Tierra del Fuego.

Operating through its wholly owned subsidiary, Netherfield Corporation, which is based in Buenos Aires, Antrim has become a leading foreign independent in Argentina. The Company holds a 40% working interest and is joint operator of the Puesto Guardian oil field in the NorthWest Basin.

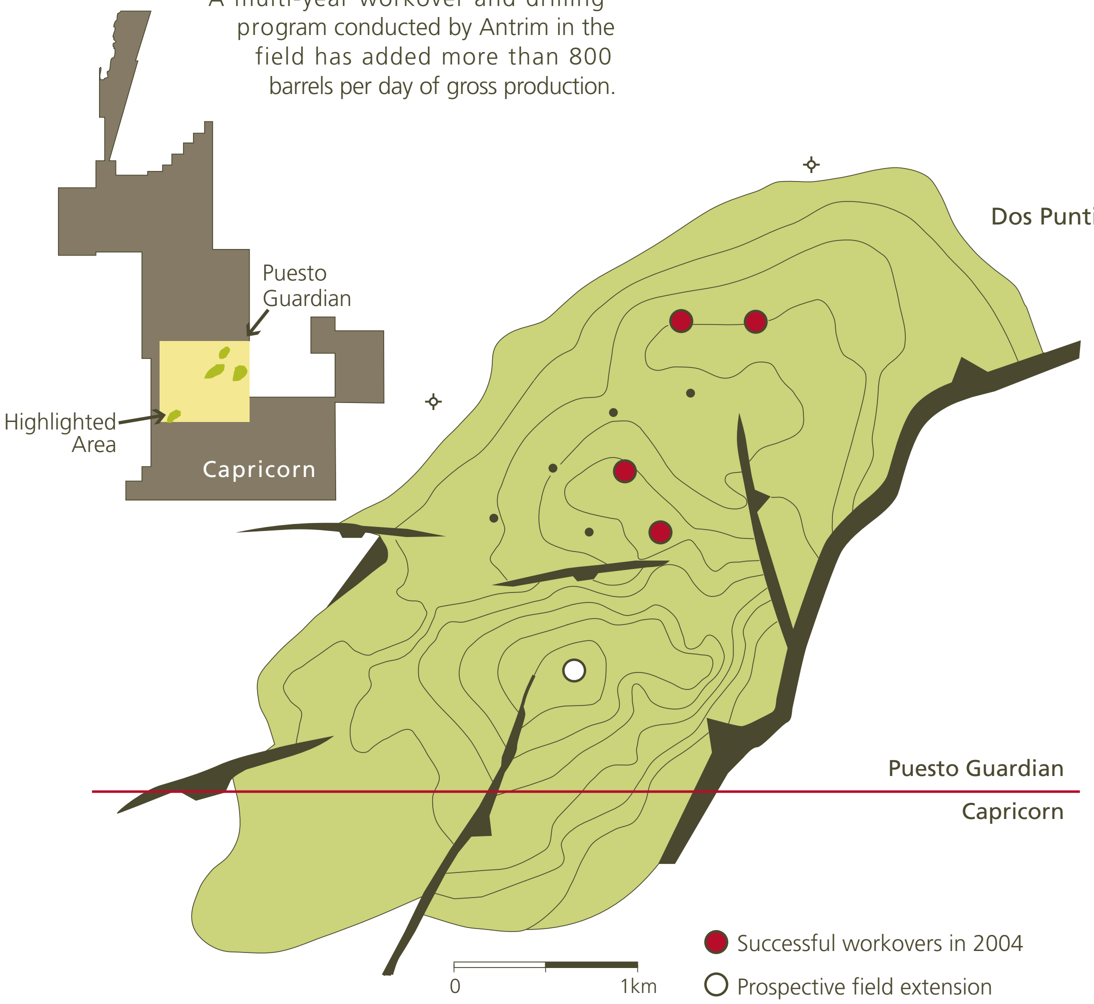
A multi-year workover and drilling program conducted by Antrim in the field has added more than 800 barrels per day of gross production.

In 2004, Antrim also completed construction of a new battery on the Dos Puntitas Pool that will support the re-completion of three wells and the drilling of a fourth well in 2005.

The work completed by the end of the year had increased the Company's average daily production from the Puesto Guardian Field to more than 500 barrels per day.

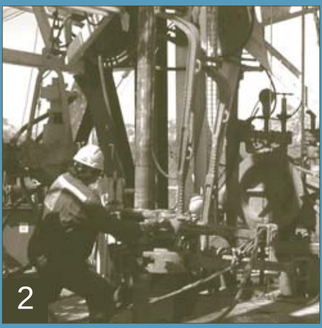
In 2004, Antrim also began work for a seismic survey and drilling program on its 50% owned, 2,000,000 gross acre Capricorn Exploration Licence.

Antrim will continue investing in the Puesto Guardian Field and the adjacent Capricorn Exploration Licence in 2005, with the long term objective of securing at least 1,000 barrels per day of net-interest production in the NorthWest Basin. This ambitious target will require drilling new wells and constructing additional infrastructure as well as continuing to add production through successful well re-completions.




Puesto Guardian
Capricorn
ARGENTINA
Buenos Aires
Tierra del
Fuego

ANTRIM WILL CONTINUE THE SUCCESSFUL INVESTMENT IN ITS PROPERTIES IN THE NORTHWEST AND TIERRA DEL FUEGO AREAS WITH A TARGET OF ACHIEVING A PRODUCTION LEVEL OF SEVERAL THOUSAND BARRELS PER DAY FROM OUR COMBINED PROPERTIES IN ARGENTINA. THIS AMBITIOUS TARGET WILL REQUIRE SEVERAL YEARS OF INVESTMENT IN DEVELOPMENT WORK, INCLUDING WORKOVERS AND NEW DRILLING.



1 Gas Plant: Tierra del Fuego

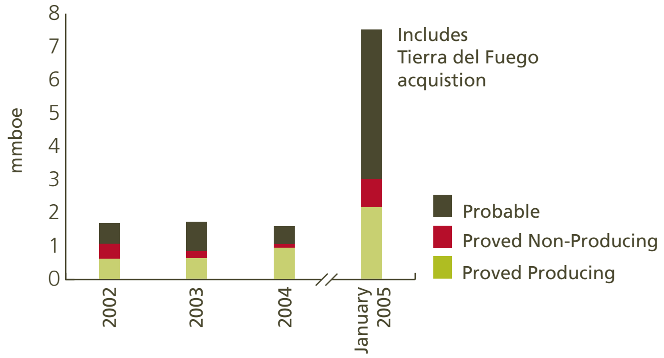
2 Drilling: Puesto Guardian

3 Oil wells: Tierra del Fuego

4 Workover: Puesto Guardian

Subsequent to the year-end, Antrim Energy capitalized on its operating relationships in Argentina to acquire a 25.78% working interest in three licences totalling 521,000 acres (134,000 net) in Tierra del Fuego, on the Antarctic-facing tip of Argentina. The acquisition included independently reviewed and certified (by Ryder Scott) net reserves of 1.2 mmboe* proven producing, 0.7 mmboe proven undeveloped and 4.0 mmboe probable. The property also has current net daily production of 138 barrels of crude oil, 2.6 million cubic feet of gas and 50 barrels of natural gas liquids (all net to Antrim's interest) from 20 oil wells and 15 gas wells.

* *The boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*



Estimated Reserves (mmboe)

Tierra del Fuego has one of the most attractive fiscal regimes of any oil producing region in the world. The area has been designated a special economic zone by the Argentine government since 1972 to attract and secure economic activity. Fiscal terms include a 12% flat royalty rate and no corporate, export or value-added taxes. Oil and NGL are sold at world market prices to domestic refineries or for export. Gas is sold to domestic buyers at regulated sales prices that are currently low ($.50 – $.80/mcf) but are expected to rise over time starting in mid-2005. Tierra del Fuego has recently attracted several of the world's largest exploration and development companies, which have made significant investments to acquire acreage and develop production in the area.

Antrim has a high working interest in the Tierra del Fuego Licences and has like-minded and very active partners. The Company and its partners are conducting a large 300 km^2 3-D seismic survey during the first quarter of 2005, in preparation for an aggressive drilling program starting later in the year. In addition to onshore drilling locations, there are prospective near-offshore exploration targets, some of which could be directionally drilled from onshore. The Company will also evaluate these targets during 2005.

Development of Argentina's 2.6 billion barrels of proved and probable commercial oil reserves and 22 trillion cubic feet of natural gas is fundamental to the long term economic success of this resource-rich nation. Currently it produces approximately 700,000 barrels of oil and 3.5 billion cubic feet of natural gas per day.

Australia

In 2004, Antrim drilled a dry hole on one of two offshore exploration permits it holds on the Australian NorthWest Shelf. The South Galapagos #1 well tested a seismically defined structural target on permit WA-306-P, 200 kilometres southwest of the large Scott Reef gas and condensate field.

ONGC Videsh, a wholly-owned subsidiary of India's largest integrated petroleum company, joined the drilling consortium and funded most of the cost of the well in return for earning an interest in the permit.

There is a considerable amount of geological data from the new well that is to be analyzed before Antrim and its partners decide upon further exploration on the permit. Meanwhile, Antrim continues to hold a 50% working interest in the adjacent permit WA-307-P.

Antrim's 2004 drilling operation on Australia's NorthWest Shelf. Pictured is the semi-submersible drilling platform, the Sedco 703, drilling the South Galapagos #1 well in 140 metres of water 300 km from the Australian coastline.

Tanzania

Political uncertainty surrounding future revenue sharing between local and state authorities in 2004 again delayed the planned seismic exploration on Antrim's 100% working interest 3.5 million acre Pemba-Zanzibar Exploration Licence in Tanzania's East African Coastal Basin. Antrim's holdings are located offshore and onshore on the islands of Pemba and Zanzibar.

In 2003, Antrim identified several promising frontier drilling locations based on an analysis of previously-shot seismic. The intention is to confirm the drilling locations with additional geophysical surveys. Antrim is confident that the issues of jurisdiction and resource revenue sharing will be resolved.

Statistical Review

UNDEVELOPED LANDS

The following table sets forth information respecting Antrim's unproved properties as at December 31, 2004.

Country	*Project*	*Working Interest (%)*	*Acreage Gross*	*Net*
			Gross	Net
Argentina	Puesto Guardian	40.00	302,000	120,800
Capricorn		50.00	2,000,000	1,000,000
Australia	WA-306-P	32.50	1,200,000	390,000
	WA-307-P	50.00	850,000	425,000
United Kingdom	South Larne	42.86	86,485	37,067
	Block 42/21	15.00	59,774	11,955
	Block 42/22	15.00	59,774	11,955
	Block 42/23	60.00	59,774	35,864
	Block 211/22a	57.60	36,942	21,278
Tanzania	Pemba	100.00	3,500,000	3,500,000
Total			8,154,749	5,553,919

RESERVES RECONCILIATION

The following table summarizes the changes in Antrim's gross share of reserves, before deduction of royalties owned by others, from December 31, 2003 to December 31, 2004. This information does not include data relating to the purchase of oil and gas assets in Tierra del Fuego, Argentina. The Tierra del Fuego acquisition closed in February 2005.

	January 1, 2004 Opening Balance (mboe)	*Net Additions (mboe)*	*Revisions (mboe)*	*Dispositions (mboe)*	*Production (mboe)*	*January 1, 2005 Opening Balance (mboe)*
Proved Producing	608	–	507	–	179	**936**
Proved Non-producing	220	–	(116)	–	–	**104**
Total proved	828	–	391	–	179	**1,040**
Probable	877	–	(338)	–	–	**539**
Total	1,705	–	53	–	179	**1,579**

1 *The definitions of the various categories of reserves are those set out in National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101").*

2 *Reserves stated above are based on forecast cost and price assumptions.*

3 *Columns may not add due to rounding.*

4 *Does not include the purchase of reserves in Tierra del Fuego, Argentina which was completed in February, 2005.*

OIL AND NATURAL GAS RESERVES AND NET PRE-TAX CASH FLOWS

(based on forecast cost and price assumptions)

Antrim's Interest in Reserves

	Oil (mbbls)		*NGL's (mbbls)*		*Natural Gas (mmcf)*		*Total (mboe)*	
December 31,2004	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Net*
Argentina								
Proven:								
Developed Producing	857	751	–	–	–	–	857	751
Non-Producing	104	91	–	–	–	–	104	91
Total Proven	961	843	–	–	–	–	961	843
Probable	522	458	–	–	–	–	522	458
TOTAL (Argentina)	1,483	1,301	–	–	–	–	1,483	1,301
Czech Republic								
Proven:								
Developed Producing	–	–	–	–	474	451	79	75
Non-Producing	–	–	–	–	–	–	–	–
Total Proven	–	–	–	–	474	451	79	75
Probable	–	–	–	–	101	96	17	16
TOTAL (Czech Republic)	–	–	–	–	575	546	96	91
CUMULATIVE TOTALS								
Proven:								
Developed Producing	857	751	–	–	474	451	936	826
Non-Producing	104	91	–	–	–	–	104	91
Total Proven	961	843	–	–	474	451	1,040	918
Probable	522	458	–	–	101	96	539	474
TOTAL	1,483	1,301	–	–	575	546	1,579	1,392

OIL AND NATURAL GAS RESERVES AND NET PRE-TAX CASH FLOWS

(based on forecast cost and price assumptions)

Present Value Cash Flow BIT

($C 000's)	*PV (0%)*	*PV (10%)*	*PV (15%)*	*PV (20%)*
Argentina				
Proven:				
Developed Producing	13,419	10,905	9,965	9,179
Non-Producing	2,204	1,566	1,345	1,167
Total Proven	15,623	12,471	11,309	10,346
Probable	10,433	6,659	5,503	4,633
TOTAL (Argentina)	26,056	19,130	16,812	14,979
Czech Republic				
Proven:				
Developed Producing	1,909	1,256	1,064	921
Non-Producing	–	–	–	–
Total Proven	1,909	1,256	1,064	921
Probable	626	282	199	144
TOTAL (Czech Republic)	2,535	1,538	1,263	1,065
CUMULATIVE TOTALS				
Proven:				
Developed Producing	15,329	12,161	11,029	10,101
Non-Producing	2,204	1,566	1,345	1,167
Total Proven	17,533	13,727	12,373	11,267
Probable	11,058	6,941	5,702	4,777
TOTAL	28,591	20,668	18,076	16,044

OIL AND GAS PRICE FORECAST

(effective January 1, 2005)

		Crude Oil Prices (US$/stb)	*Natural Gas Prices (US$/mcf)*
Year	*WTI*	*Puesto Guardian Crude*	*Czech Gas Price*
2005	42.00	$ 29.40	$ 5.05
2006	39.50	29.03	5.15
2007	37.00	27.80	5.25
2008	35.00	27.11	5.36
2009	34.50	26.91	5.47
2010	34.30	26.83	5.58
2011	35.00	27.11	5.69
2012	35.70	27.36	5.80
2013	36.40	27.61	5.92
2014	37.10	27.83	6.04
	2% thereafter	2% thereafter	2% thereafter

Corporate Governance

Antrim Energy Inc. is a publicly traded, shareholder-owned company. The common shares are listed on the Toronto Stock Exchange and the London Stock Exchange (AIM). Canadian regulatory requirements and standards prevail. The management is accountable to an independent Board of Directors elected by the Shareholders at the annual meeting. The directors have a duty to ensure that the Company acts in the best interests of all shareholders. The qualifications of the directors meet the regulatory requirements and practices of the Toronto Stock Exchange and the relevant securities regulatory bodies. The independent directors are kept fully informed by the executive management of all the Company's dealings and opportunities. They are advised in a timely manner of all material transactions. They exercise their authority on behalf of the shareholders in an orderly, open process.

Antrim Energy has active oil and gas operations in the United Kingdom, Argentina and Australia and owns a 100% operating interest in an oil and natural gas concession in Tanzania. The Company is compliant with all the regulatory requirements of its host countries.

Antrim Energy's corporate governance standards are aligned with the Guidelines of the Toronto Stock Exchange. Canadian and North American equity markets are in a period of transition and change as regulators in consultation with the financial sector and operating public companies revise the regulatory framework to meet higher shareholder expectations for scrutiny, compliance and accountability. Antrim Energy's directors and executive management are cognizant of their obligation to monitor, understand and meet the burden of responsibility imposed by changes to standards. As a conservatively managed company with prudent internal standards and processes of accountability, Antrim is compliant with regulatory requirements and considers and addresses the underlying issues that prompt changes in business and regulatory standards and expectations of shareholders.

MD&A

The following management discussion and analysis ("MD&A") is as of March 22, 2005 and should be read in conjunction with Antrim's consolidated financial statements and accompanying notes for the year ended December 31, 2004. The calculations of barrels of oil equivalent ("BOE") are based on a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. Unless otherwise stated, all dollar amounts are expressed in Canadian dollars.

This MD&A contains forward looking statements. Forward looking statements are based on current expectations that involve a number of risks and uncertainties which could cause actual events or results to differ materially from those reflected in the MD&A. Such risks, uncertainties and other factors include the uncertainties inherent in oil and gas exploration and development activities, the effect of actions by third parties, fluctuations in world oil prices and other risks detailed in the Company's Annual Report and Annual Information Form ("AIF"). Additional information relating to the Company including the Company's AIF is on SEDAR at www.sedar.com. Antrim assumes no obligation to update forward looking statements should circumstances or management's estimates change.

OVERVIEW

In 2004 the Company positioned itself to continue to participate in high risk/high reward drilling opportunities by increasing its production base and entering into strategic farm-outs with strong industry partners.

FINANCIAL AND OPERATING RESULTS

Financial Results

	2004	2003	2002
($000's except per share amounts)			
Oil and gas revenue	$ **6,900**	$ 5,142	$ 5,997
Cash flow from operations	**400**	(211)	1,451
Cash flow from operations per share	**0.01**	(0.01)	0.07
Net earnings (loss)	**(5,586)**	(2,987)	1,102
Net earnings (loss) per share	**(0.16)**	(0.15)	0.06
Total assets	**35,124**	25,988	20,628
Working capital	**20,325**	15,344	10,974
Capital expenditures	**6,362**	4,436	1,474
Debt	$ **–**	$ –	$ –
Common shares outstanding *(000's)*			
End of year	**39,487**	31,302	20,049
Weighted average – basic	**33,966**	20,505	20,001
Weighted average – fully diluted	**34,644**	21,521	20,711
Production			
Oil and natural gas production (BOE per day)	**491**	405	466

Oil and Gas Revenue

Oil and gas revenue increased to $6,899,965 in 2004 compared to $5,141,596 in 2003. Oil and gas revenue increased due to an increase in average oil production to 468 barrels of oil per day compared to 382 barrels in 2003. Oil production increased following the implementation in the second half of 2003 of a pressure maintenance scheme and workover program. A second workover program commenced in August 2004 which further increased production. Oil production in the fourth quarter of 2004 was 508 barrels of oil per day compared to 429 barrels for the comparable period in 2003.

Oil prices averaged $38.66 per barrel in 2004 compared to $34.80 per barrel in 2003. Oil revenues, positively impacted by higher world crude oil prices, have been negatively impacted by the strengthening Canadian dollar compared to the US dollar. In addition, in May and August 2004 the Argentine government mandated that the previous 10% discount on domestic oil sales be increased to 20% when the price of West Texas Intermediate ("WTI") crude oil is equal to US$36.00 per barrel to a high of approximately 30% when the price of WTI crude oil is equal to or greater than US$46.00 per barrel. Should WTI be less than US$36.00 per barrel, the mandated discount is now 14%. No pricing hedges were entered into in 2004 or 2003.

Gas production and revenue from the Czech Republic was consistent with the prior year.

Netbacks

Higher commodity prices and lower per unit operating costs resulted in Antrim realizing a higher per unit netback of $25.85/BOE in 2004 compared to a per unit netback of $19.52/BOE in 2003. The table below provides a comparative analysis of field netbacks for 2004 compared to 2003.

	Twelve Months Ended December 31,	
	2004	*2003*
Wellhead price ($/BOE)	38.50	34.82
Royalties ($/BOE)	(5.42)	(4.64)
Operating expenses ($/BOE)	(7.22)	(10.66)
Netback ($/BOE)	25.85	19.52
Oil and natural gas production (BOE)	179,213	147,680

While the average price of WTI increased 33% in 2004 to US$41.45 compared to US$31.10 in 2003, the Company's wellhead price increased by only 11% due to a stronger Canadian dollar and a higher discount on domestic oil sales in Argentina.

General and Administrative

General and administrative costs ("G&A") increased in 2004 to $2,671,769 compared to $2,098,486 in 2003. G&A increased primarily due to costs associated with the farm-out of part of Antrim's interest in the South Galapagos #1 well and increased corporate costs related to persuing and developing transaction opportunities in Argentina, Australia and United Kingdom.

Depletion & Depreciation

Depletion and depreciation expense increased in 2004 to $1,402,458 compared to $988,209 in 2003 as a result of increased oil and gas production in the year. The majority of the Company's depletion charge continues to be with respect to production in Argentina. Depletion and depreciation charged to the Company's various cost centres in 2004 were as follows: Argentina – $1,136,500, Czech Republic – $142,629 and office equipment – $123,329. The consolidated per unit charge was $7.83 per BOE in 2004 compared to $6.69 per BOE in 2003.

Foreign Exchange Loss

The Company incurred foreign exchange losses in 2004 of $636,295 (2003 – $228,739) as a result of the strengthening of the Canadian dollar against the US dollar and Argentina peso in the second half of 2004 and the strengthening in the fourth quarter of 2004 of the Australian dollar versus both the Canadian and US dollar. Substantially all of the Company's revenues are denominated in US dollars against which many currencies, including the Canadian dollar, appreciated against during the year. The Company seeks to minimize exposure to foreign currency and other country risks by maintaining only the required minimum cash balance in all foreign jurisdictions.

Write-off of Impaired Assets

In 2004 and 2003 the Company recorded a write-down of its Australian and Tunisian assets of $3,017,114 and $2,399,575, respectively. These charges were recorded following the drilling and subsequent abandonment in October 2004 of the Company's South Galapagos #1 well and a decision in 2003 by the joint venture group to fully withdraw from the Tunisia licence following an unsuccessful well on the licence early that year.

In addition, the Company recorded a write-down in 2004 of $1,190,649 with respect to its Tanzania property as a result of the application of CICA AcG – 11 "Enterprises in the Development Stage" which requires a write-down of capitalized costs when there has been a delay in development activity that extends beyond three years. Since the lifting of force majeure in April 2002, a dispute between the federal and provincial governments in Tanzania has prevented the Company from incurring the expenditures set out in the Production Sharing Agreement ("PSA") governing the significant acreage held by the Company in Tanzania. The Company anticipates that once the dispute between the federal and provincial governments is resolved, the Company will have access to the full first and second two year exploration periods set out in the PSA.

Income Taxes

Antrim recorded current income tax expense in 2004 of $1,251,464 (2003 – $951,922) and future income tax recoveries of $32,605 (2003 – $710,515). The Company is currently taxable in Argentina and the Czech Republic. The Company is unable to apply operating losses in other countries to offset income and income taxes payable in Argentina and the Czech Republic.

Capital Expenditures

Petroleum and natural gas expenditures in 2004 were $6,361,713 compared to $4,436,050 in 2003. Capital expenditures increased in 2004 following the drilling of the South Galapagos #1 well offshore Australia in October 2004 and the acquisition in 2004 of new licences in the United Kingdom.

Cash Flow and Net Income

Antrim generated net cash flow from operations of $399,852 ($0.01 per share) in 2004 compared to cash outflow of $210,890 ($0.01 per share) in 2003. Cash flow from operations increased due to higher oil and gas revenues. Cash flow from operations and cash flow from operations per share does not have a standard meaning under generally accepted accounting principles ("GAAP") and may not be comparable to other companies. Management believes that cash flow is a useful supplementary measure that may assist investors.

The Company recorded a net loss of $5,586,139 ($0.16 per share) in 2004 compared to net loss of $2,986,648 ($0.15 per share) the previous year. Net loss increased primarily as a result of the write-down in 2004 of costs associated with the drilling of the South Galapagos #1 well offshore Australia, impairment of the costs associated with the Company's Tanzanian PSA and higher general and administrative and foreign currency costs.

FINANCIAL RESOURCES AND LIQUIDITY

As at December 31, 2004, the Company had working capital of $20,324,848 (2003 – $15,343,761), including cash of $21,477,705 (2003 – $15,136,075) and no bank debt.

The Company intends to focus its activities in 2005 on two primary areas, Argentina and the United Kingdom.

In February 2005 the Company completed the acquisition of a 25.78% working interest in three producing exploitation concessions in the Tierra del Fuego region of Argentina. The cost of the acquisition was approximately US$5.7 million after closing adjustments and was funded from existing working capital. In addition, the Company provided a US$1.5 million loan to the operator of the concessions secured by and to be repaid from production from the concessions. The acquisition, which added approximately 140 barrels of oil, 2.6 mmcf of natural gas and 60 barrels of LPG (butane and propane) per day to Antrim production, should result in increased revenue and cash flow in 2005

As a result of farm-out agreements announced in November 2004 and March 2005, the Company expects to participate in 2005 in two wells to be drilled on its UK North Sea acreage at no additional cost to the Company. The success of these wells will determine the pace at which the Company and its joint venture partners seek to drill additional wells on the Company's UK licences. As in Argentina, the Company seeks to participate in additional exploration and development opportunities in the United Kingdom. The Company seeks new oil and gas properties that offer significant working interests with low entry costs and established infrastructure. However, a significant acquisition of this nature or drilling program would likely require raising additional equity and or debt financing.

CRITICAL ACCOUNTING POLICIES

A summary of the Company's significant accounting policies is presented in Note 1 to the consolidated financial statements. In accounting for oil and gas activities, the Company uses the full cost method instead of the successful efforts method.

Effective January 1, 2004, the Company adopted Accounting Guideline AcG-16 "Oil and Gas Accounting – Full Cost". This guideline amends the ceiling test calculation and the calculation of depletion.

Effective, January 1, 2004, the Company adopted CICA Handbook Section 3110 "Asset Retirement Obligations". This standard requires that the estimated amount of such obligations be added to the cost of petroleum and natural gas properties and be recorded as a liability. Adoption of this standard eliminated a current Canadian/US GAAP difference created by the earlier issuance of the US standard.

Effective January 1, 2004, the Company adopted CICA Handbook Section 3870 "Stock Based Compensation and Other-Stock Based Payments". This standard requires the Company to measure all stock-based compensation using the fair value method of accounting and recognize the result as compensation expense in the financial statements.

The Company reconciles its consolidated financial statements prepared in accordance with Canadian generally accepted accounting principles ("GAAP") with accounting principles generally accepted in the United States. See Note 12 to the consolidated financial statements for a reconciliation of Canadian to U.S. GAAP.

CRITICAL ACCOUNTING ESTIMATES

Preparing financial statements in accordance with GAAP requires management to make certain judgments and estimates. Changes to these judgments and estimates could have a material effect on the Company's financial statements and financial position. The estimates of proved and probable reserves is critical to many aspects of the Company's financial statements, including net income and the carrying amount of petroleum and natural properties and future abandonment and site restoration liabilities.

The Company also incurs costs related to properties for which no proved reserves may be attributable. These costs must also be assessed to ascertain whether impairment has occurred. In certain instances, the Company may be required under GAAP to record an impairment charge against these costs even though the Company has and intends to maintain the underlying licence or agreement pertaining to the properties.

COMMITMENTS AND CONTINGENCIES

The Company has several commitments in respect of its petroleum and natural gas properties. These commitments and commitments under operating leases for office space are set out in Notes 3 and 9 respectively to the consolidated financial statements.

RELATED PARTY TRANSACTIONS

In 2004, the Company paid fees of $59,604 (2003 – $56,250) to a company controlled by a director of the Company for services related to listing and acquisition activities in the United Kingdom. The Company also paid fees of $6,500 (2003 – $38,000) to a company controlled by a director of the Company for services related to acquisition activities in Argentina.

BUSINESS RISKS

Exploration, development, production and marketing of oil and natural gas involves a wide range of risks which include but are not limited to the uncertainty of finding new commercial fields, securing markets for existing reserves, commodity price fluctuations, exchange and interest rate costs and changes to government regulations, including regulations relating to prices, taxes, royalties, land tenure, allowable production and environmental protection. The oil and natural gas industry is intensely competitive and the Company competes with a large number of companies that have greater resources.

The Company's ability to increase reserves in the future will depend not only on its ability to develop its present properties but also on its ability to select and acquire suitable producing properties or prospects. The acquisition and development of properties also requires that sufficient funds, including funds from outside sources, will be available in a timely manner. The availability of equity or debt financing is affected by many factors, many of which are outside the control of the Company.

The Company has significant investments in several foreign countries. A number of risks are associated with conducting foreign operations over which the Company has no control, including currency instability, potential and actual civil disturbances, restriction of funds movement outside of these countries, the ability of joint venture partners to fund their obligations, changes of laws affecting foreign ownership and existing contracts, environmental requirements, crude oil and natural gas price and production regulation, royalty rates, OPEC quotas, potential expropriation of property without fair compensation and possible interruption of oil exports.

The Company's primary source of revenue has been from the Puesto Guardian oil field in Argentina. In 2005, the Company acquired a working interest in a second producing oil and natural gas field in Argentina. While the economic and political instability within the country has not had a material impact on the Company's ability to operate and move funds outside the country, the overall impact of the crisis in Argentina has been to negatively impact foreign investment in the country.

ENVIRONMENT, HEALTH AND SAFETY

The Company is committed to meeting its responsibilities to protect the environment wherever it operates. Management sets company-wide standards, monitors environmental performance and ensures that staff is kept informed about environmental issues.

Because the Company is engaged in worldwide exploration and development of natural resources, we have a special obligation to understand and comply with the regulations of each country we operate in. We have procedures in place to ensure utmost care is taken in the day-to-day management of our properties.

Our international base has placed increased emphasis on health and safety issues. The Company is committed to a set of principles, and follows established health and safety guidelines in all areas of operation. In broad terms, we strive to provide safe, healthy operations while respecting the interests of the communities in which we operate.

Quarterly Information

Quarterly Information
(Thousands of dollars, except number of common shares and per share amounts)
(Unaudited)

	Fourth Quarter		*Third Quarter*		*Second Quarter*		*First Quarter*	
	2004	*2003*	*2004*	*2003*	*2004*	*2003*	*2004*	*2003*
Revenue								
Oil and Gas	**$ 1,881**	$ 1,363	**$ 1,743**	$ 1,290	**$ 1,677**	$ 1,010	**$ 1,599**	$ 1,478
Royalties	**(278)**	(160)	**(230)**	(193)	**(267)**	(165)	**(198)**	(167)
	1,604	1,203	**1,513**	1,097	**1,410**	845	**1,401**	1,311
Interest and other income	**124**	52	**82**	49	**51**	11	**69**	75
	1,728	1,255	**1,595**	1,146	**1,461**	856	**1,470**	1,386
Expenses								
Operating	**325**	545	**266**	398	**290**	443	**413**	189
General and administrative	**956**	801	**744**	539	**579**	466	**393**	293
Stock based compensation	**109**	35	**105**	32	**90**	29	**71**	25
Depletion and depreciation	**296**	370	**402**	219	**358**	182	**347**	217
Accretion of asset retirement obligations	**7**	19	**10**	8	**8**	7	**8**	7
Foreign exchange loss	**541**	(155)	**111**	51	**29**	325	**(44)**	8
Write off of impaired assets	**3,510**	509	**698**	–	**–**	–	**–**	1,890
	5,744	2,124	**2,335**	1,247	**1,354**	1,452	**1,188**	2,629
Income (loss) before below noted dispositions and income taxes	**(4,016)**	(869)	**(740)**	(101)	**107**	(596)	**282**	(1,243)
Gain on disposition of petroleum and natural gas properties	**–**		**–**	64	**–**			–
Income (loss) for the quarter before income taxes	**(4,016)**	(869)	**(740)**	(37)	**107**	(596)	**282**	(1,243)
Income taxes (recovery)	**297**	110	**305**	165	**348**	85	**269**	(118)
Net income (loss) for the quarter	**(4,313)**	(979)	**(1,045)**	(202)	**(241)**	(681)	**13**	(1,125)
Deficit – beginning of quarter	**(12,032)**	(9,780)	**(10,988)**	(9,578)	**(10,747)**	(8,897)	**(10,759)**	(7,772)
Deficit – end of quarter	**$ (16,345)**	$ (10,759)	**$ (12,032)**	$ (9,780)	**$ (10,988)**	$ (9,578)	**$ (10,746)**	$ (8,897)
Income (loss) per share:								
Basic	**$ (0.11)**	$ (0.05)	**$ (0.03)**	$ (0.01)	**$ (0.01)**	$ (0.03)	**$ 0.00**	$ (0.06)
Fully diluted	**(0.11)**	(0.05)	**(0.03)**	(0.01)	**(0.01)**	(0.03)	**0.00**	(0.06)
Weighed average number of shares								
Basic	**39,278**	20,103	**33,771**	20,066	**31,387**	20,062	**31,351**	20,049
Fully diluted	**39,956**	21,119	**41,365**	21,110	**32,820**	20,527	**32,655**	20,514
Outstanding number of shares, end of quarter	**39,487**	31,302	**38,573**	20,103	**31,403**	20,084	**31,387**	20,062

Management's Responsibility for Financial Reporting

The accompanying financial statements are the responsibility of management. The financial statements have been prepared by management in accordance with the accounting policies outlined in the notes to the financial statements. Financial statements include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. In the opinion of management, the financial statements have been prepared within acceptable limits of materiality and are in accordance with Canadian generally accepted accounting principles. The financial information contained in the annual report is consistent with that in the financial statements.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized, assets are safeguarded and financial records are properly maintained to provide reliable information for the preparation of financial statements.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent annual general meeting, to examine the financial statements in accordance with Canadian generally accepted auditing standards and provide an independent professional opinion.

The audit committee of the Board of Directors, with all of its members being outside directors, have reviewed the financial statements including notes thereto, with management and PricewaterhouseCoopers LLP. The financial statements have been approved by the Board of Directors on the recommendation of the audit committee.

[signed]

STEPHEN GREER
President and Chief Executive Officer
March 22, 2005

[signed]

ANTHONY J. POTTER, CA
Chief Financial Officer

Auditor's Report

We have audited the consolidated balance sheets of Antrim Energy Inc. as at December 31, 2004 and 2003 and the consolidated statements of income (loss) and deficit and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and 2003 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004 in accordance with Canadian generally accepted accounting principles.

[signed]

PricewaterhouseCoopers LLP
Chartered Accountants
March 22, 2005

Consolidated Balance Sheets

AS AT DECEMBER 31, 2004 AND 2003

	2004	2003 (restated)
ASSETS		
Current assets		
Cash and short-term deposits	$ 21,477,705	$ 15,136,075
Accounts receivable	3,489,087	1,038,046
Inventory and other	199,445	618,793
	25,166,237	16,792,914
Petroleum and natural gas properties *(note 3)*	9,791,904	9,003,637
Office equipment – net of accumulated amortization of $503,949 (2003 – $380,620)	165,767	191,466
	$ 35,123,908	$ 25,988,017
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	4,163,522	1,447,908
Income taxes payable	677,867	1,245
	4,841,389	1,449,153
Future income taxes *(note 5)*	33,838	66,443
Asset retirement obligation *(note 8)*	284,882	337,669
	5,160,109	1,853,265
SHAREHOLDERS' EQUITY		
Capital stock *(note 4)*	45,813,132	34,772,554
Contributed Surplus	495,718	121,110
Deficit	(16,345,051)	(10,758,912)
	29,963,799	24,134,752
	$ 35,123,908	$ 25,988,017

Approved by the Board of Directors

[signed]

V. Neill Martin
Director

[signed]

Dr. Gerry Orbell
Director

Consolidated Statements of Income (loss) and Deficit

FOR THE YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002

	2004	2003 (restated)	2002 (restated)
REVENUE			
Oil and gas	$ **6,899,965**	$ 5,141,596	$ 5,996,959
Royalties	**(972,063)**	(685,127)	(824,610)
	5,927,902	4,456,469	5,172,349
Interest and other income	**326,083**	186,673	214,782
	6,253,985	4,643,142	5,387,131
EXPENSES			
Operating	**1,294,605**	1,574,885	945,633
General and administrative	**2,671,769**	2,098,486	1,441,994
Stock based compensation	**374,608**	121,110	–
Depletion and depreciation	**1,402,458**	988,209	1,273,031
Accretion of asset retirement obligations	**33,767**	40,993	26,970
Foreign exchange loss	**636,295**	228,739	641,003
Write off of impaired assets *(note 3)*	**4,207,763**	2,399,575	1,550,597
	10,621,265	7,451,997	5,879,228
Income (loss) before below noted dispositions and income taxes	**(4,367,280)**	(2,808,855)	(492,097)
Gain on disposition of petroleum and natural gas properties	–	63,614	1,906,879
Income (loss) for the year before income taxes	**(4,367,280)**	(2,745,241)	1,414,782
Income taxes (recovery) *(note 5)*			
Current	**1,251,464**	951,922	907,508
Future	**(32,605)**	(710,515)	(594,711)
	1,218,859	241,407	312,797
Net income (loss) for the year	**(5,586,139)**	(2,986,648)	1,101,985
Deficit – Beginning of year as previously reported	**(10,758,912)**	(7,772,264)	(8,854,840)
Retroactive Adjustment for Change in Accounting Policy	–	–	(19,409)
Deficit – End of year	$ **(16,345,051)**	$ (10,758,912)	$ (7,772,264)
Net income (loss) per common share:			
Basic	(0.16)	(0.15)	0.06
Diluted	(0.16)	(0.15)	0.06

Consolidated Statements of Cash Flows

FOR THE YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002

	2004	2003 (restated)	2002 (restated)
Cash provided by (used in)			
OPERATING ACTIVITIES			
Net income (loss) for the year	$ **(5,586,139)**	$ (2,986,648)	$ 1,101,985
Items not involving cash			
Depletion and depreciation	**1,402,458**	988,209	1,273,031
Accretion of asset retirement obligations	**33,767**	40,993	26,970
Write off of impaired assets	**4,207,763**	2,399,575	1,550,597
Stock based compensation expense	**374,608**	121,110	–
Gain on disposition of petroleum and natural gas properties	**–**	(63,614)	(1,906,879)
Future income taxes	**(32,605)**	(710,515)	(594,711)
	399,852	(210,890)	1,450,993
Change in non-cash working capital items	**1,344,077**	(351,949)	(419,959)
	1,743,929	(562,839)	1,031,034
FINANCING ACTIVITIES			
Issue of common shares	**11,636,026**	10,096,314	30,734
Share issue costs	**(637,087)**	(903,925)	–
	10,998,939	9,192,389	30,734
INVESTING ACTIVITIES			
Office equipment	**(97,630)**	(208,572)	(20,512)
Petroleum and natural gas properties	**(6,361,713)**	(4,436,050)	(1,473,683)
Proceeds from sale of properties	**–**	–	6,774,731
Change in non-cash working capital items `	**58,105**	363,338	(430,581)
	(6,401,238)	(4,281,284)	4,849,955
Increase in cash and short-term deposits	**6,341,630**	4,348,266	5,911,723
Cash and short-term deposits – Beginning of year	**15,136,075**	10,787,809	4,876,086
Cash and short-term deposits – End of year	$ **21,477,705**	$ 15,136,075	$ 10,787,809

Notes to Consolidated Financial Statements

1. SIGNIFICANT ACCOUNTING POLICIES

Basis of presentation

The Company expenses all costs associated with general corporate overhead in the period in which they are incurred. Expenditures incurred in respect of foreign properties are capitalized as exploration and development expenditures provided the Company is successful in negotiating a production sharing agreement, concession or license. Otherwise the costs are written off against income.

All cost centres of the Company are considered by management to be in the pre-production stage except for the Czech and Argentina cost centres which have attained a commercial level of production. All costs associated with activities in the pre-production cost centres are capitalized, net of revenues, and recorded as petroleum and natural gas properties.

Consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries.

Petroleum and natural gas properties

The Company follows the full cost method of accounting for oil and gas operations whereby all costs of exploring for and development of oil and gas reserves are capitalized into a cost centre for each country in which the Company's subsidiaries have operations. Such costs will include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells and general and administration costs directly related to exploration and development activities.

The ultimate recovery of the costs capitalized to date by cost centre is dependent upon the existence of economically recoverable reserves in each country, the maintenance of the necessary agreements with the applicable regulatory authorities and the ability to obtain the necessary financing to complete the development of its holdings. Costs of acquiring and evaluating unproved properties and major development projects are initially excluded from the depletion and depreciation calculation. These costs are assessed periodically to ascertain whether impairment has occurred. When proven reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion and depreciation.

Costs subject to depletion, including tangible production equipment are depleted using the unit-of-production method based on estimated proven reserves of petroleum and natural gas before royalties as determined by an independent reserve engineer. Reserves are converted to equivalent units on the basis of approximate relative energy content. Gains or losses on the sale or disposition of petroleum and natural gas properties are not ordinarily recognized except under circumstances which result in a change of 20% or more in the depletion rate.

The Company applies a ceiling test to capitalized costs to ensure that such costs do not exceed undiscounted future net revenues from estimated production of proven reserves, using estimates of future prices and costs.

Office equipment

The Company depreciates its office and computer equipment using the straight-line method at a rate of 20% and 30% respectively.

Joint ventures

Certain of the Company's petroleum and natural gas activities are conducted jointly with others and accordingly the accounts reflect only the Company's proportionate interest in such activities.

Asset retirement obligation

The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when identified and a reasonable estimate of fair value can be made. Asset retirement obligations include those legal obligations where the Company will be required to retire tangible long-lived assets such as producing well sites and processing facilities. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long lived asset.

Changes in the estimated obligation resulting from revisions to estimated timing or amount of undiscounted cash flows are recognized as a change in the asset retirement obligation and the related asset retirement cost.

Asset retirement costs for crude oil and natural gas assets are amortized using the unit-of-production method. Amortization of asset retirement costs are included in depletion and depreciation in the Consolidated Statement of Income (Loss). Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligations in the Consolidated Statement of Income (Loss).

Foreign currency translation

Operations of the Company's subsidiaries are considered to be integrated and therefore the financial statements of the subsidiaries are included in these consolidated financial statements on the basis that monetary assets and liabilities are translated at the exchange rate in effect at year-end, non-monetary assets and liabilities are translated at historical rates and revenues and expenses are translated at the monthly average exchange rate. Exchange gains and losses are included in general and administrative expenses.

Cash and cash equivalents

Cash and cash equivalents consist of cash on deposit and short-term investments, maturing within 90 days at the time of acquisition.

Inventory

Inventories of crude oil, refined products and supplies are valued at the lower of average cost and net realizable value.

Stock-based compensation plans

Stock-based compensation costs are recognized over the vesting period of the stock options granted.

Income taxes

The Company follows the liability method of accounting for income taxes. Under this method, income tax assets and liabilities are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantially enacted tax rates expected to apply when the asset is realized or the liability settled. Future income tax assets are only recognized to the extent it is more likely than not that sufficient future taxable income will be available to allow the future income tax asset to be realized.

Financial instruments

The Company's financial instruments consist of cash and short-term deposits, accounts receivable and accounts payable and accrued liabilities. The fair values of these financial instruments approximate their carrying amounts due to the short-term maturity of these instruments.

Measurement uncertainty

The amounts recorded for depletion, depreciation and amortization of property and equipment and the provision for asset retirement obligations are based on estimates. The ceiling test is based on estimates of proved reserves, production rates, prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

Per share amounts

Basic earnings per share is calculated by dividing earnings by the weighted average number of common shares outstanding during the period. Diluted earnings per share reflect the potential dilution that could occur if stock options were exercised. The treasury stock method is used to determine the dilutive effect of stock options. Under the treasury stock method, only proceeds received from the exercise of "in the money" stock options are used to determine the impact on the diluted calculations.

Comparative amounts

Certain comparative figures have been reclassified to conform with the current year presentation.

2. CHANGES IN ACCOUNTING POLICIES

Asset Retirement Obligations

On January 1, 2004 the Company retroactively adopted the new Canadian accounting standard related to "Asset Retirement Obligations" ("ARO"). Under the new standard, the estimated amount of such obligations is added to the cost of petroleum and natural gas properties and is recorded as a liability. The fair value of the ARO is recorded on a discounted basis. The liability accretes until the Company settles the obligation.

The 2003 impact of adopting this standard compared to the previous standard is as follows:

	As Reported	Increase (Decrease)	Restated
Petroleum and natural gas properties	$ 8,904,908	$ 98,729	$ 9,003,637
Site restoration provision	257,180	80,489	337,669
Deficit	(10,656,042)	(18,240)	(10,637,802)
Depletion and depreciation expense	1,031,852	(43,643)	988,209
Accretion of asset retirement obligations	–	40,993	40,993
Net loss for the year	(2,868,188)	(2,650)	(2,865,538)
Net loss per common share:			
Basic	(0.14)	–	(0.14)
Diluted	$ (0.14)	$ –	$ (0.14)

The total future asset retirement obligation was estimated by management based on the Company's net ownership interest in the wells and facilities, the estimated cost to abandon and reclaim the wells and facilities and the estimated timing of such costs.

Stock-based Compensation Costs

On January 1, 2004 the Company adopted CICA Handbook Section 3870 "Stock Based Compensation and Other-Stock Based Payments". The standard requires the Company to measure all stock-based compensation using the fair value method of accounting and recognize the result as compensation cost in the financial statements. Stock-based compensation costs are recognized over the vesting period of the stock options granted.

The 2003 impact of adopting this standard was to increase general and administrative expenses for the year ended December 31, 2003 by $121,110 with a corresponding increase to contributed surplus. Net loss per common share increased from $0.14 per share to $0.15 per share. The impact of adopting this standard on the balance sheet as at December 31, 2003 was to increase deficit and contributed surplus by $121,110.

3. PETROLEUM AND NATURAL GAS PROPERTIES

		2004	
	Cost	*Accumulated depletion and depreciation*	*Net book value*
Australia	$ 4,251,789	$ 3,017,114	$ 1,234,675
Tanzania	1,190,649	1,190,649	–
Argentina	12,212,945	8,174,327	4,038,618
United Kingdom	4,398,045	761,561	3,636,484
Czech Republic	1,997,544	1,115,417	882,127
	$ 24,050,972	$ 14,259,068	$ 9,791,904

		2003	
	Cost	*Accumulated depletion and depreciation*	*Net book value*
Australia	$ 1,172,733	$ –	$ 1,172,733
Tanzania	1,161,031	–	1,161,031
Argentina	11,251,148	7,037,827	4,213,321
Tunisia	3,560,172	3,560,172	–
United Kingdom	2,190,357	761,561	1,428,796
Czech Republic	2,000,544	972,788	1,027,756
	$ 21,335,985	$ 12,332,348	$ 9,003,637

The benchmark prices used in the ceiling test evaluation of the Company's crude oil and natural gas reserves at December 31, 2004 were:

Year	*WTI Crude Oil (US$/Barrel)*	*Natural Gas (US$/Mcf)*
2005	42.00	5.05
2006	39.50	5.15
2007	37.00	5.25
2008	35.00	5.36
2009	34.50	5.47
2010	34.30	5.58
% increase thereafter	2%	2%

In 2004 and 2003 the Company recorded a write-down of its Australian and Tunisian assets of $3,017,114 and $2,399,575, respectively following the drilling in each country of an unsuccessful well. In addition, the Company recorded a write-down in 2004 of $1,190,649 with respect to its Tanzania property as a result of the application of CICA AcG – 11 "Enterprises in the Development Stage" which requires a write-down of capitalized costs when there has been a delay in development activity that extends beyond three years. See Commitments – Tanzania. In 2002, the Company recorded asset impairment charges of $1,160,597 and $390,000 with respect to costs in Tunisia and the Czech Republic respectively.

During the year, the Company capitalized $802,119 (2003 – $873,004) of general and administrative costs related to exploration and development activity.

At December 31, 2004, petroleum and natural gas properties include $4,871,159 (2003 – $3,762,560) relating to unproven properties that have been excluded from the depletion calculation.

Commitments

The Company has the following commitments in respect of its oil and gas properties:

Argentina

In accordance with the terms of the Company's Capricorn Licence, the Company is required to drill in the second exploration period one exploratory well prior to August 2007 or relinquish the licence. Antrim holds a 50% working interest in the Capricorn Licence.

Australia

The Company holds a 32.5% and 50% working interest in permits WA-306-P and WA-307-P respectively. Under the terms of the Company's permits, one exploratory well must be drilled on each permit prior to July 2005. In October 2004 the Company drilled on permit WA-306-P the South Galapagos #1 well which was subsequently abandoned. The Company is currently evaluating with its partners the technical results from this well and has requested an extension with respect to the requirement to drill a well on the adjacent permit, WA-307-P. Should the technical results conclude that further activity on the permits not be undertaken or if an extension to the drilling requirement is not received, the costs associated with one and or both of the permits will be impaired and a write-down required.

Tanzania

The Company holds a 100% interest in the Pemba-Zanzibar Production Sharing Agreement (PSA). As a result of a dispute between the federal and provincial governments in Tanzania, the parties agreed that effective May 14, 1998, the PSA would be put in a condition of force majeure. On April 19, 2002 the condition of force majeure was lifted and it was agreed between the parties that the requirements of the first and second two year exploration periods to incur cumulative expenditures of U.S. $3.5 million and U.S. $4.0 million would be extended to April 19, 2004 and April 19, 2006 respectively.

Since the lifting of force majeure, further disputes between the federal and provincial governments in Tanzania have prevented the Company from incurring the expenditures set out in the PSA and despite further extensions granted to the Company to incur these expenditures, the Company is not able under CICA AcG – 11 "Enterprises in the Development Stage" to carry its interest in the PSA at cost. The Company anticipates that once the disputes between the federal and provincial governments are resolved, the Company will have access to the full first and second two year exploration periods.

United Kingdom

In accordance with the terms of the Company's South Larne Licence in Northern Ireland, the Company is required to undertake various technical studies and drill one exploratory well prior to October 2006. The Company has a one-third working interest in the Licence.

On October 1, 2003, the Company was officially awarded UK North Sea Licence P. 1132 containing two blocks ("Blocks 42/21 and 42/22") in the North Sea southern gas basin. On December 1, 2004, the Company was officially awarded a Licence for an adjoining block ("Block 42/23"). Antrim has a 60% interest in both Licences. The Company has two years from the official award of each Licence to commit to drill one well on the blocks covered by the Licence or drop the block(s). In February 2005, the Company entered into a farmout agreement with a third party under which the Company will be carried for the cost of a well to be drilled on Blocks 42/21 and 42/22.

In 2004, the Company acquired an interest in UK North Sea Licence P.201 ("Block 211/22a") which contains a fallow discovery. In order to maintain the Licence, the Company committed to drill one well on the Licence in 2005. In March 2005 the Company entered into a farmout agreement with a third party under which the Company will be carried for a significant portion of the estimated cost of a well on the Licence. It is anticipated that this well will satisfy the well commitment made to maintain the Licence.

4. CAPITAL STOCK

a) Authorized

Unlimited number of common voting shares

Unlimited number of preferred shares

b) Common shares issued

	Number of shares	*Amount $*
Balance – December 31, 2001	19,965,283	25,486,065
Employee share ownership plan *(note 4(f))*	83,800	61,467
Balance – December 31, 2002	20,049,083	25,547,532
Exercise of stock options	10,000	9,000
Employee share ownership plan *(note 4(f))*	71,296	65,267
Private placement of units *(note 4(c))*	11,171,867	10,054,680
Private placement issue costs	–	(903,925)
Balance – December 31, 2003	31,302,246	34,772,554
Exercise of stock options	692,333	537,266
Employee share ownership plan *(note 4(f))*	64,484	82,939
Private placement of units *(note 4(c))*	4,687,500	7,500,000
Private placement of shares	14,500	13,920
Exercise of warrants *(note 4(c))*	2,725,800	3,543,540
Private placement issue costs	–	(637,087)
Balance – December 31, 2004	39,486,863	45,813,132

c) Units

On December 18, 2003, the Company issued 4,397,367 units at a price of $0.90 per unit for gross proceeds of $3,957,630. On December 23, 2003, the Company issued 6,774,500 units at a price of $0.90 per unit for gross proceeds of $6,097,050. Each unit consisted of one common share and one-half common share purchase warrant. Each whole warrant entitled the holder thereof to acquire one common share at a price of $1.30 per common share for a period of twelve months. In 2004, 2,725,800 warrants were exercised and 2,860,133 warrants expired unexercised.

On August 24, 2004, the Company issued 4,687,500 units at a price of $1.60 per unit for gross proceeds of $7,500,000. Each unit consisted of one common share and one-half common share purchase warrant.

The Company also issued 468,750 broker warrants, exercisable at a price of $1.60 per unit, each unit consisting of one common share and one-half common share purchase warrant. Each whole warrant entitles the holder thereof to acquire one common share at a price of $2.10 per common share for a period of twelve months. At December 31, 2004, none of the warrants or broker warrants had been exercised.

d) Stock options

The Company has established a stock option plan whereby the Company may grant options to its directors, officers, employees and consultants for up to 3,000,000 common shares. The exercise price of each option is no less than the market price of the Company's stock on the date of grant. Stock option terms are determined by the Company's Board of Directors but typically vest evenly over a period of three years from the date of grant and expire five years after the date of grant. A summary of the status of the Company's stock option plan is presented below.

	2004 Shares	2004 Weighted-average exercise price	2003 Shares	2003 Weighted-average exercise price
Outstanding - Beginning of year	**1,593,000**	**0.84**	1,760,000	0.89
Granted	**1,220,000**	**1.21**	305,000	0.82
Expired	**(20,000)**	**1.20**	(150,000)	0.91
Cancelled	–	–	(312,000)	1.09
Exercised	**(692,333)**	**0.78**	(10,000)	0.90
Outstanding – End of year	**2,100,667**	**1.07**	1,593,000	0.84
Options Exercisable – End of year	**796,499**	**0.93**	1,051,670	0.83

The following table summarizes information about the stock options outstanding at December 31, 2004:

Options outstanding: Range of exercise prices	Weighted-average exercise price	Number Outstanding at December 31, 2004	Weighted-average remaining contractual life	Options exercisable: Range of exercise prices	Weighted-average exercise price	Number Outstanding at December 31, 2004
0.76 – 1.00	0.89	996,667	2.50	0.80 – 1.00	0.89	702,499
1.01 – 1.65	1.24	1,104,000	3.81	1.01 – 1.20	1.20	94,000
		2,100,667				796,499

Stock-based compensation costs are recognized over the vesting period of the stock options granted.

The fair value of each stock option granted during the quarter is estimated on the date of grant using the Black-Scholes option pricing model based on the following:

	2004	2003
Risk free interest rate	**4.5%**	4.5%
Expected life (years)	**5.00**	5.00
Expected volatility	**67.5%**	65.0%
Expected dividend yield	–	–

Stock-based compensation costs do not include costs associated with stock options granted prior to January 1, 2002. Stock based compensation costs in 2004 were $374,608 (2003 – $121,110).

e) Per share information

The weighted average number of common shares outstanding during the year was 33,966,079 (2003 – 20,505,479; 2002 – 20,000,740). The fully diluted weighted average number of common shares outstanding during the year was 34,644,412 (2003 – 21,521,149; 2002 – 20,710,740).

f) Employee share ownership plan

The Company has adopted an employee share ownership plan ("ESOP"). Under the terms of the plan, employees may contribute between 1% and 10% of their gross annual salary, subject to a minimum of $500 per annum, with the Company matching that contribution on a 1:1 basis. Purchases are to be made on a quarterly basis at a price per share equal to the average price for the five days preceding the issuance. The maximum number of common shares issuable pursuant to the ESOP shall not exceed 400,000 common shares. The maximum number of common shares issuable in any one year period pursuant to the ESOP, Stock Option Plan and all other established or proposed share compensation arrangements shall not exceed 10% of the outstanding common shares. During the year, the Company issued 64,484 common shares at an average price of $1.29 per share. Of this amount, employees contributed $41,470 with the Company matching that contribution.

5. INCOME TAXES

The differences between the expected income tax provision and the reported income tax provision are summarized as follows:

	2004	2003	2002
Income (loss) before income taxes	**$ (4,367,280)**	$ (2,745,241)	$ 1,414,782
Statutory income tax rate	**33.87%**	36.74%	42.24%
Expected tax expense (recovery)	**(1,479,198)**	(1,008,602)	597,604
Increase (decrease) in taxes resulting from:			
Non-taxable accounting gains	–	–	(805,466)
Benefit of tax losses not recognized	**2,665,692**	1,299,601	671,175
Foreign income subject to higher rate	**39,337**	–	–
Foreign income subject to lower rate	**(6,972)**	(49,592)	(150,516)
	$ 1,218,859	$ 241,407	$ 312,797

The components of the Company's net future income tax liability are as follows:

	2004	2003
Future income tax liabilities:		
Carrying value of capital assets in excess of tax basis	**(33,838)**	(66,443)
Net future income tax asset (liability)	**$ (33,838)**	$ (66,443)

At December 31, 2004, the Company has Canadian non-capital loss carry forwards in the amount of approximately $7,684,000 (2003 - $6,599,000), expiring at various dates from 2005 - 2011. The Company incurs losses in several of the countries that it operates in, while generating taxable income in Argentina and Czech Republic. No accounting recognition has been given to the losses.

6. SEGMENTED INFORMATION

		2004				
		Revenue		***Earnings (loss)***		***Identifiable assets***
Argentina	$	**6,601,626**	$	**1,654,886**	$	**6,795,097**
Australia		**–**		**(3,670,442)**		**4,179,396**
Canada		**–**		**(2,179,921)**		**18,901,156**
Czech Republic		**298,339**		**(21,532)**		**1,444,105**
New Zealand		**–**		**(15,719)**		**5,558**
Tanzania		**–**		**(1,193,020)**		**635**
United Kingdom		**–**		**(160,391)**		**3,797,961**
Total	$	**6,899,965**	$	**(5,586,139)**	$	**35,123,908**

		2003				
		Revenue		*Earnings (loss)*		*Identifiable assets*
Argentina	$	4,852,696	$	497,440	$	6,660,814
Australia		–		2,361		1,470,129
Canada		–		(1,579,798)		13,944,753
Czech Republic		288,900		(64,413)		1,264,841
New Zealand		–		(48,060)		14,233
Tanzania		–		(11,579)		1,161,712
Tunisia		–		(1,693,260)		–
United Kingdom		–		(89,339)		1,471,535
Total	$	5,141,596	$	(2,986,648)	$	25,988,017

		2002				
		Revenue		*Earnings (loss)*		*Identifiable assets*
Argentina	$	5,712,974	$	1,260,081	$	5,917,409
Australia		–		(9,029)		585,660
Canada		–		(895,867)		8,772,043
Czech Republic		283,985		(365,360)		1,451,426
New Zealand		–		1,920,573		23,740
Tanzania		–		(4,024)		1,046,088
Tunisia		–		(785,043)		1,730,619
United Kingdom		–		(19,346)		1,101,366
Total	$	5,996,959	$	1,101,985	$	20,628,351

7. SUPPLEMENTAL CASH FLOW INFORMATION

	2004	2003	2002
Operating activities:			
Decrease (increase) in current assets:			
Accounts receivable	$ (2,267,816)	$ (281,928)	$ 755,558
Inventory and other	179,751	(166,631)	22,784
Increase (decrease) in current liabilities			
Accounts payable and accrued liabilities	2,713,881	619,399	(1,785,701)
Income taxes payable	676,622	(555,422)	556,667
Increase (decrease) in capital stock	41,639	32,633	30,733
	$ 1,344,077	$ (351,949)	$ (419,959)
Investing activities:			
Decrease (increase) in current assets:			
Accounts receivable	(183,225)	(39,907)	(1,037,126)
Inventory and other	239,597	797,529	–
Increase (decrease) in current liabilities			
Accounts payable and accrued liabilities	1,733	(394,284)	606,545
	$ 58,105	$ 363,338	$ (430,581)
Interest received	321,241	186,673	182,458
Taxes paid	$ 573,597	$ 941,074	$ 350,841

8. ASSET RETIREMENT OBLIGATIONS

At December 31, 2004, the estimated undiscounted asset retirement obligations are US$584,000 and US$23,000 for Argentina and Czech Republic, respectively. The present value of the asset retirement obligations has been calculated using a credit adjusted risk free rate of 8.0% and an inflation rate of 2.0%.

Changes to asset retirement obligations were as follows:

	2004	2003
Asset retirement obligations, beginning of year	337,669	296,676
Accretion expense	33,767	40,993
Increase in liabilities	90,885	–
Change in estimates	(177,439)	–
Asset retirement obligations, end of year	284,882	337,669

9. COMMITMENTS AND CONTINGENCIES

In addition to commitments in respect of its oil and gas properties (see note 3), the Company is committed to payments under operating leases for office space, net of sub-lease arrangements, for the next five years as follows:

Year	*$*
2005	215,988
2006	176,124
2007	167,156
2008	182,352
2009	182,352
	923,972

10. RELATED PARTY TRANSACTIONS

In 2004, the Company paid fees of $59,604 (2003 – $56,250) to a company controlled by a director of the Company for services related to listing and acquisition activities in the United Kingdom. The Company also paid fees of $6,500 (2003 – $38,000) to a company controlled by a director of the Company for services related to acquisition activities in Argentina.

11. SUBSEQUENT EVENT

On February 14, 2005, the Company completed the purchase of producing oil and natural gas assets in the Tierra del Fuego region in southern Argentina. The assets consist of an effective 25.78% working interest in three producing exploitation concessions. The cost of the acquisition was approximately US$5.7 million after closing adjustments, and was funded from existing working capital.

12. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING

Reconciliation of consolidated financial statements to United States generally accepted accounting principles

These consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP") which, in most respects, conforms to accounting principles generally accepted in the United States of America ("U.S. GAAP"). Any significant differences in those principles, as they apply to the Company's statements of income, balance sheets and statements of cash flow, are as follows:

a) Under U.S. GAAP the carrying value of petroleum and natural gas properties and related facilities, net of future or deferred income taxes, is limited to the present value of after tax future net revenue from proven reserves, discounted at 10 percent (based on prices and costs at the balance sheet date), plus the lower of cost and fair value of unproven properties. Under Canadian GAAP, a similar ceiling test calculation is performed with the exception that cash flows from proved reserves are undiscounted and utilize forecast pricing to determine whether impairment exists.

Application of the full cost ceiling test under U.S. GAAP would have resulted in the following additional write-downs of capitalized costs:

Year	*Property*	*Before Tax*	*After Tax*
2003	Czech Republic	97,000	82,430
2002	Czech Republic	160,000	110,400
2001	Argentina	500,000	325,000

The above write-downs of petroleum and natural gas properties result in a decrease in depletion expense and income tax recovery under U.S. GAAP in subsequent years.

b) Effective January 1, 2004, the Canadian Accounting Standard's Board amended the Full Cost Accounting Guideline. Under Canadian GAAP, depletion charges are calculated by reference to proved reserves estimated using estimated future prices and costs. Under U.S. GAAP, depletion charges are calculated by reference to proved reserves estimated using constant prices. No adjustments are required to net income for the year ended December 31, 2004 as a result of this difference.

c) SFAS 130, "Comprehensive Income", requires the reporting of comprehensive income in addition to net earnings. Comprehensive income includes net income plus other comprehensive income. Management believes that no adjustments are required to net income to determine comprehensive income.

d) On January 1, 2004, the Company implemented under Canadian GAAP, EIC 128 "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments which requires derivatives not designated as hedges to be recorded in the balance sheet as either assets or liabilities at their fair value. Changes in the derivative's fair value are recognized in current period earnings. Under the transitional rules any gain or loss at the implementation date is deferred and recognized into revenue once realized.

SFAS 133, "Accounting for Derivative Instruments and Hedging Activities", as amended by SFAS 137 and SFAS 138, was issued in June 1998 by the FASB. SFAS 133 requires that all derivatives be recorded in the balance sheet as either assets or liabilities at their fair value. Changes in the derivative's fair value are recognized in current period earnings unless specific hedge accounting criteria are met. The effective date of SFAS 133 for the Company was January 1, 2001.

At December 31, 2004, 2003 and 2002, the Company had no derivative instruments outstanding.

e) Effective January 1, 2004, the Company adopted CICA Handbook Section 3110 "Asset Retirement Obligations". Adoption of this standard eliminated a U.S. GAAP reconciling item created by the earlier issuance of US standard U.S. SFAS No. 143 "Accounting for Asset Retirement Obligations". For U.S. reporting purposes the Company adopted SFAS No. 143 effective January 1, 2003.

U.S. GAAP requires the cumulative impact of a change in an accounting policy be presented in the current year Consolidated Statement of Income (Loss) and prior periods not be restated. In 2003, the Company recognized a credit to income of $15,590 as the cumulative effect of an accounting change related to the adoption of SFAS No. 143.

f) Under U.S. GAAP, enacted tax rates are used to calculate future taxes, whereas Canadian GAAP uses substantively enacted tax rates.

Consolidated Statements of Income

The application of U.S. GAAP would have the following effect on net income:

Year ended December 31,		***2004***		*2003*		*2002*
Net income (loss) for the year, as reported	$	**(5,586,139)**	$	(2,986,648)	$	1,101,985
Adjustments:						
Ceiling test write-down, net of tax *(a)*		–		(82,430)		(110,400)
Depletion, net of tax *(a)*		**93,058**		89,373		32,500
Accounting for asset retirement obligations *(e)*						(34,999)
Future tax recovery adjustment		**(30,332)**		(157,500)		–
		(5,523,413)		(3,137,205)		989,086
Cumulative effect of change in accounting principle *(e)*		–		15,590		–
Net income (loss) for the year, U.S. GAAP	$	**(5,523,413)**	$	(3,121,615)	$	989,086
Net income per common share, U.S. GAAP:						
Basic		**(0.16)**		(0.15)		0.05
Diluted		**(0.16)**		(0.15)		0.05
Depletion and depreciation expense, U.S. GAAP		**1,309,400**		939,829		1,285,000
Write off of impaired assets, U.S. GAAP		**4,207,763**		2,496,575		1,710,597
Future income tax expense (recovery), U.S. GAAP		**(2,273)**		(567,585)		(626,811)

Consolidated Balance Sheets

The application of U.S. GAAP would have the following effect on the consolidated balance sheets:

			December 31, 2004
	As reported	Increase (decrease)	U.S. GAAP
Assets			
Petroleum and natural gas properties (a)	9,791,904	(524,570)	9,267,334
Liabilities			
Future income taxes (a)	33,838	(33,838)	–
Shareholders' equity			
Deficit	(16,345,051)	(490,732)	(16,835,783)

			December 31, 2003
	As reported	Increase (decrease)	U.S. GAAP
Assets			
Petroleum and natural gas properties (a)	9,003,637	(617,628)	8,386,009
Liabilities			
Future income taxes (a)	66,443	(64,170)	2,273
Shareholders' equity			
Deficit	(10,758,912)	(553,458)	(11,312,370)

Consolidated Statements of Cash Flows

The application of U.S. GAAP would not change the amounts as reported under Canadian GAAP for cash flows provided by (used in) operating, investing or financing activities, except for the following:

a) The consolidated statements of cash flows include, under investing activities, changes in non-cash working capital items, such as accounts payable and accounts receivable, related to the non-cash elements of property and equipment additions. This disclosure is provided in order to disclose the aggregate costs related to such activities and to identify the non-cash component thereof and to arrive at the cash amounts. This presentation is not permitted under U.S. GAAP.

Recent Accounting Pronouncements

In 2004, FASB issued revised SFAS 123 "Share Based Payment". This amended statement eliminates the alternative to use Accounting Principles Board ("APB") Opinion No. 25's intrinsic value method of accounting, as was provided in the originally issued Statement 123. As a result, public entities are required to use the grant-date fair value of the award in measuring the cost of employee services received in exchange for an equity award of equity instruments. Compensation cost is required to be recognized over the requisite service period. For liability awards, entities are required to re-measure the fair value of the award at each reporting date up until the settlement date. Changes in fair value of liability awards during the requisite service period are required to be recognized as compensation cost over the vesting period. Compensation cost is not recognized for equity instruments for which employees do not render the requisite service. This amended statement is effective the beginning of the first interim or annual reporting period that begins after June 15, 2005.

In 2004, FASB issued SFAS 153 "Exchange of Non-monetary Assets". This statement is an amendment of APB Opinion no. 29 "Accounting for Non-monetary Transactions". Based on the guidance in APB Opinion No. 29, exchanges of non-monetary assets are to be measured based on the fair value of the assets exchanged. Furthermore, APB Opinion No. 29 previously allowed for certain exceptions to this fair value principle. FAS 153 eliminates APB Opinion No. 29's exception to fair value for non-monetary exchanges of similar productive assets and replaces this with a general exception for exchanges of non-monetary assets which do not have commercial substance. For purposes of this statement, a non-monetary exchange is defined as having commercial substance when the future cash flows of an entity are expected to change significantly as a result of the exchange. The provisions of this statement are effective for non-monetary asset exchanges which occur in fiscal periods beginning after June 15, 2005 and are to be applied prospectively. Currently this statement does not have an impact on the Company.

SUPPLEMENTAL FINANCIAL INFORMATION
SUPPLEMENTAL OIL AND GAS DISCLOSURES – UNAUDITED

Costs Incurred

Costs incurred for oil and gas property acquisition, exploration and development activities are as follows:

Year ended December 31,	***2004***	*2003*	*2002*
Acquisition costs:			
Proven properties	**–**	585,200	–
Unproven properties	**1,677,018**	–	–
Development costs	**1,045,351**	1,060,613	627,371
Exploration costs	**3,639,344**	2,790,237	846,312
Total costs incurred	**6,361,713**	4,436,050	1,473,683

SUPPLEMENTAL RESERVE INFORMATION
SUPPLEMENTAL OIL AND GAS DISCLOSURES – UNAUDITED

Standardized Measure Of Discounted Future Net Cash Flows Relating To Proved Oil And Gas Reserves

The following information has been developed utilizing procedures prescribed by SFAS No. 69 Disclosure about Oil and Gas Producing Activities ("SFAS 69") and based on crude oil reserve and production volumes estimated by the Company's engineering staff. It may be useful for certain comparative purposes, but should not be solely relied upon in evaluating the Company or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of the Company.

The Company believes that the following factors should be taken into account in reviewing the following information: *(1)* future costs and selling prices will probably differ from those required to be used in these calculations; *(2)* actual rates of production achieved in future years may vary significantly from the rate of production assumed in the calculations; *(3)* selection of a 10% discount rate is arbitrary and may not be reasonable as a measure of the relative risk inherent in realizing future net oil and gas revenues; and *(4)* future net revenues may be subject to different rates of income taxation.

Under the Standardized Measure, future cash inflows were estimated by applying period-end oil prices, adjusted for fixed and determinable escalations, to the estimated future production of period-end proven reserves. Future cash inflows were reduced by estimated future development, abandonment and production costs based on period-end costs in order to arrive at net cash flow before tax. Future income tax expense has been computed by applying period-end statutory tax rates to aggregate future pre-tax net cash flows, reduced by the tax basis of the properties involved and tax carry forwards. Use of a 10% discount rate is required by SFAS No. 69.

SUPPLEMENTAL RESERVE INFORMATION
SUPPLEMENTAL OIL AND GAS DISCLOSURES – UNAUDITED

Management does not rely solely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proven reserves and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves is as follows:

			December 31, 2004
(Cdn$000s)	***Argentina***	***Czech Republic***	***Total***
Future cash inflows	**29,925**	**3,024**	**32,949**
Future production costs	**(10,139)**	**(968)**	**(11,107)**
Future development costs	**(1,419)**	**(20)**	**(1,439)**
Future net cash flows before income taxes	**18,367**	**2,036**	**20,403**
Future income taxes	**(6,925)**	**(499)**	**(7,424)**
Total undiscounted future net cash flows	**11,442**	**1,537**	**12,979**
10% annual discount for estimated timing of cash flows	**(2,635)**	**(515)**	**(3,150)**
Standardized measure of discounted future net cash flows	**8,807**	**1,022**	**9,829**

			December 31, 2003
(Cdn$000s)	*Argentina*	*Czech Republic*	*Total*
Future cash inflows	23,103	1,864	24,967
Future production costs	(6,223)	(606)	(6,829)
Future development costs	(1,320)	(22)	(1,342)
Future net cash flows before income taxes	15,560	1,236	16,796
Future income taxes	(5,310)	(143)	(5,453)
Total undiscounted future net cash flows	10,250	1,093	11,343
10% annual discount for estimated timing of cash flows	(2,261)	(302)	(2,563)
Standardized measure of discounted future net cash flows	7,989	791	8,780

SUPPLEMENTAL RESERVE INFORMATION
SUPPLEMENTAL OIL AND GAS DISCLOSURES – UNAUDITED

A summary of the changes in the standardized measure of discounted future net cash flows applicable to proved oil and gas reserves is as follows:

Year ended December 31,	***2004***	*2003*	*2002*
(Cdn$000s)			
Standardized measure, beginning of year	**$ 8,780**	$ 12,363	$ 5,171
Sales of production, net of production costs	**(4,607)**	(2,882)	(4,227)
Net change in sales prices, net of production costs	**(3,112)**	(1,365)	11,077
Additions to proved reserves resulting from extensions, discoveries and additions	**–**	–	–
Development costs related to beginning of year reserves	**–**	–	–
Changes in estimated future development costs	**(190)**	632	835
Revisions in quantity estimates	**8,145**	(1,307)	2,067
Accretion of discount	**878**	981	763
Sale of reserves	**–**	–	–
Net change in income tax	**(2,524)**	399	(2,290)
Changes in production rates (timing) and other	**2,459**	(41)	(1,033)
Net increase (decrease)	**1,049**	(3,583)	7,192
Standardized measure, end of year	**$ 9,829**	$ 8,780	$ 12,363

Board of Directors

STEPHEN GREER, *President and Chief Executive Officer, Antrim Energy Inc.*

Mr. Greer has served as Chief Executive Officer of Antrim Energy Inc. since September 1999. Mr. Greer was previously Chairman and Managing Director of a predecessor corporation, Antrim International, and President and Chief Executive Officer of Antrim Resources Inc., a private oil and gas company. Mr. Greer has over 25 years of petroleum exploration experience and a technical background in oil and gas exploration, gained from various positions with companies including Texaco Canada Inc. and BP Canada Inc., both public oil and gas companies. Mr. Greer received a M.Sc in Geology from the University of Witwatersrand in Johannesburg, South Africa.

V. NEILL MARTIN, *Senior Partner, D&S International Consultants Ltd.*

Mr. Martin has more than 35 years of experience in a series of senior executive responsibilities, both domestic and international. He is presently Senior Partner of D&S International and D&S Reservoir Engineering, which is headquartered in Calgary. During the past 20 years Mr. Martin has held academic positions with the University of Calgary and the Banff School of Advanced Management. Mr. Martin holds a B.Sc. (Geology), M.Sc. (Geophysics) and an MBA.

DR. GERRY ORBELL, *Chairman, Antrim Energy Inc.*

Dr. Orbell is a petroleum geologist with more than thirty years of international experience. He previously served as Executive Director, Exploration and Production, of Premier Oil plc, where he was responsible for the worldwide oil and gas exploration and production program involving Albania, Pakistan, Tunisia and the U.K. From 1983 to 1992, Dr. Orbell served in various senior management roles with Fina Petroleum Development Ltd. and Fina Exploration, including Director of Oil Exploration and Production. Dr. Orbell holds a PhD (Geology) from University College in London and has been a member of the American Association of Petroleum Geologists since 1975. He is a member of the Board of Valpak Ltd. of the U.K.

JAY ZAMMIT, *Partner, Burstall Winger LLP*

Mr. Zammit attended the University of Manitoba and received a Bachelor of Commerce (Finance) in 1982, following which he served as a consultant to the International Air Transport Association. Mr. Zammit obtained a Bachelor of Laws in 1987 from the University of Manitoba and was admitted to the Alberta Bar in 1988.

Mr. Zammit's preferred areas of practice include corporate finance and commercial law. He was seconded to the Alberta Securities Commission in 1989. Mr. Zammit has advised on various public and private financing transactions as well as trusts, funds, reorganizations, takeovers, mergers, shareholder disputes and strategic relationships. Mr. Zammit served on the executive of the Business Law Subsection of the Canadian Bar Association for several years.

JIM PERRY, *President, CEO and Director, Alternative Fuel Systems (2004) Inc.*

Mr. Perry is President, CEO and a Director of Alternative Fuel Systems (2004) Inc. ("AFS"), a TSX-Venture listed company. Prior to joining AFS he served as President and a Director of Global Thermoelectric Inc., as President of Computalog Ltd. and Schlumberger of Canada. Mr. Perry has also previously served as a Director of Plains Energy Services Ltd. and Enertec Geophysical Services Inc. both of which were TSE listed companies. Mr. Perry is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Corporate Information

DIRECTORS

Stephen Greer [2]

President and Chief Executive Officer,
Antrim Energy Inc.

V.Neill Martin [1,2,3]

Senior Partner,
D&S International Consultants Ltd.

Gerry Orbell [2,3]

Chairman,
Antrim Energy Inc.

Jay Zammit [1,2]

Partner,
Burstall Winger LLP

Jim Perry [1]

President, CEO and Director,
Alternative Fuel Systems (2004) Inc.

[1] Member of the Audit Committee
[2] Member of the Compensation Committee
[3] Member of Reserves Committee

OFFICERS

Stephen Greer, M.Sc. (Geology)
President and Chief Executive Officer

Anthony J. Potter, C.A.
Chief Financial Officer

Dwayne Warkentin
Chief Operating Officer

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The Company's website is not incorporated by reference in and does not form a part of this Annual Report.

INTERNATIONAL SUBSIDIARIES

Antrim Energy Ltd.

Antrim Resources (N.I.) Limited

Antrim Oil and Gas Limited

Antrim Resources (Tanzania) Limited

Beheer-en Beleggingsmaatschappij Beklazo B.V.

Unimaster s.r.o

Netherfield Resources Limited

Antrim Energy Australia Pty Limited

LEGAL COUNSEL

Burstall Winger LLP

BANKERS

TD Canada Trust

AUDITORS

PricewaterhouseCoopers LLP
Calgary, Alberta

INDEPENDENT ENGINEERS

McDaniel & Associates Consultants Ltd.

REGISTRAR AND TRANSFER AGENT

Inquires regarding change of address, registered shareholdings, stock transfers or lost certificates should be directed to:

CIBC Mellon Trust Company
Calgary, Alberta

STOCK EXCHANGE LISTING

Toronto Stock Exchange:
Trading Symbol "AEN"

London Stock Exchange (AIM):
Trading Symbol "AEY"

ABBREVIATIONS

bbls	barrels
mbbls	thousand barrels
mmbbls	million barrels
bopd	barrels per day
mcf	thousand cubic feet
mmcf	million cubic feet
Tcf	trillion cubic feet
boe	barrel of oil equivalent of gas where 6,000 cubic feet of gas equals one barrel*
boepd	barrels of oil equivalent per day
mboe	thousand boe
mmboe	millions of barrels of oil equivalent
stb	stock tank barrels
mmBtu	million British thermal units
WTI	West Texas Intermediate
km	kilometres
km^2	square kilometres

* *The boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

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www.antrimenergy.com