CANARGO ENERGY CORP
Form 10-K
March 15, 2007

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

þ **ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2006
OR

o **TRANSITION REPORT UNDER SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from __________ to __________
Commission File Number 001-32145
CANARGO ENERGY CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**91-0881481**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

P.O. Box 291, St Peter Port, Guernsey, British Isles GY1 3RR
(Address of principal executive offices)
Registrant s telephone number, including area code: **+(44) 1481 729 980**
Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.10 per share	American Stock Exchange Oslo Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
YES o NO þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
YES o NO þ

Indicate by check mark whether the registrant: (1) filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
YES þ NO o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act (check one)

Large accelerated filer o Accelerated filer þ Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
YES o NO þ

The aggregate market value of the voting and non voting common equity held by-non-affiliates as of the most recently completed second fiscal quarter (June 30, 2006), based on the price at which the common equity was last sold on such date was approximately $163 million, based upon the last reported sales price of such stock on The American Stock Exchange on that date.

Indicate the number of shares outstanding of each of the registrant s classes of common stock, as of the latest practicable date: Common Stock, $0.10 par value, 238,470,390 shares outstanding as of 9 March, 2007.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant s definitive Proxy Statement issued in connection with its 2007 Annual Meeting of Shareholders are incorporated by reference in Part III of this Report. Other documents incorporated by reference in this Report are listed in the Exhibit Index.

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PART I

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K, contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 as amended (Securities Act) and Section 21E of the Securities Exchange Act of 1934 as amended (Exchange Act). When used in this Report, the words estimate, project, anticipate, expect, intend, hope, may and similar expressions, as well as will, shall and other indications of future tense, are intended to identi forward-looking statements. The forward-looking statements are based on our current expectations and speak only as of the date made. These forward-looking statements involve risks, uncertainties and other factors that in some cases have affected our historical results and could cause actual results in the future to differ significantly from the results anticipated in forward-looking statements made in this Report. Important factors that could cause such a difference are discussed in this prospectus, particularly in the sections entitled Risk Factors and Management s Discussion and analysis of Financial condition and Results of Operations . You are cautioned not to place undue reliance on the forward-looking statements.

Few of the forward-looking statements in this Report, including the documents that are incorporated by reference, deal with matters that are within our unilateral control. Joint venture, acquisition, financing and other agreements and arrangements must be negotiated with independent third parties and, in some cases, must be approved by governmental agencies. These third parties generally have interests that do not coincide with ours and may conflict with our interests. Unless the third parties and we are able to compromise their various objectives in a mutually acceptable manner, agreements and arrangements will not be consummated.

Although we believe our expectations reflected in forward-looking statements are based on reasonable assumptions, no assurance can be given that these expectations will prove to have been correct. Important factors that could cause actual results to differ materially from the expectations reflected in the forward-looking statements include, among others:

- the market prices of oil and gas;
- uncertainty of drilling results, reserve descriptions, characteristics, estimates and reserve replacement;
- operating uncertainties and hazards;
- economic and competitive conditions;
- natural disasters and other changes in business conditions;
- inflation rates;
- legislative and regulatory changes;
- financial market conditions;
- accuracy, completeness and veracity of information received from third parties;
- wars and acts of terrorism or sabotage;
- political and economic uncertainties of foreign governments; and
- future business decisions.

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In light of these risks, uncertainties and assumptions, the events anticipated by our forward-looking statements might not occur. We undertake no obligation to update or revise our forward-looking statements, whether as a result of new information, future events or otherwise.

In this Annual Report, CanArgo or the Company , we , us and our refer to CanArgo Energy Corporation and, u otherwise indicated by the context**,** our consolidated subsidiaries.

GLOSSARY OF CERTAIN TERMS

The definitions set forth below shall apply to the indicated terms as used in this Form 10-K. All volumes of natural gas referred to herein are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit and in most instances are rounded to the nearest major multiple.

AMEX The American Stock Exchange, Inc.

bbl One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

boe Barrel of oil equivalent, determined by using the ratio of one bbl of oil or natural gas liquids to six Mcf of gas.

bopd Barrels of oil produced per day.

Brent means pricing point for selling North Sea crude oil.

Development drilling The drilling of a well within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Exploration prospects or locations A location where a well is drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir or to extend a known reservoir.

Finding and development costs Costs associated with acquiring and developing proved natural gas and oil reserves which are capitalized pursuant to generally accepted accounting principles, including any capitalized general and administrative expenses.

Farm-in or farm-out An agreement under which the owner of a working interest in an oil and gas lease assigns the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a farm-in while the interest transferred by the assignor is a farm-out.

Gross acreage or gross wells The total acres or wells, as the case may be, in which a working interest is owned.

Km means kilometer.

Mcf One thousand cubic feet of natural gas.

MMcf One million cubic feet of natural gas.

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MCM One thousand cubic meters of natural gas.
mD Millidarcies.
MMbbl One million barrels.
MMboe Million barrels of oil equivalent.
Net acres or net wells The sum of the fractional working interests owned in gross acres or gross wells.
Producing property A natural gas and oil property with existing production.
Proved developed reserves Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.
Proved reserves The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.
Proved undeveloped reserves Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units that offset productive units and that are reasonably certain of production when drilled.
PSC or PSA means a Production Sharing Contract or Production Sharing Agreement.
Recomplete This term refers to the technique of drilling a separate well-bore from all existing casing in order to reach the same reservoir, or redrilling the same well-bore to reach a new reservoir after production from the original reservoir has been abandoned.
SEC means United States Securities and Exchange Commission.
Undeveloped acreage Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains proved reserves.
Working interest An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and to receive a share of production.
Workovers Operations on a producing well to restore or increase production.

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ITEM 1. BUSINESS.

General Development of Business

We operate as an oil and gas exploration and production company and as a holding company carry out our activities through a number of operating subsidiaries and associated or affiliated companies. These operating companies are generally focused on one of our projects, and this structure assists in maintaining separate cost centers for these different projects.

The address of the principal and administrative offices of CanArgo is P.O. Box 291, St Peter Port, Guernsey, British Isles GY1 3RR (Tel. No. (44) 1481 729 980).

We file reports with the Securities and Exchange Commission (the Commission). The public may read and copy any materials that we file with the Commission at the Commission s Public Reference Room at 450 Fifth Street, NW, Washington, DC 20549. We make available free of charge our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act on our internet website at www.canargo.com as soon as reasonably practicable after we electronically file or furnish such material with or to the Commission.

Our principal activities are oil and gas exploration, development and production, principally in Georgia and the Republic of Kazakhstan (Kazakhstan). We direct most of our efforts and resources to our exploration and appraisal program in Georgia, the development of the Ninotsminda Field in Georgia and to a lesser extent the **a**ppraisal and development of our Kyzyloi Field and the exploration of the Akkulka block in Kazakhstan. Our management and technical staff have substantial experience in our areas of operation. Currently our principal product is crude oil, and the sale of crude oil is our principal source of revenue.

Exploration, Development and Production Activities

In Georgia our exploration, development and production activities are carried out under four production sharing contracts or agreements (PSC or PSA), these being:

1. The Ninotsminda, Manavi and West Rustavi Production Sharing Contract, covering Block XI^{E}, (Ninotsminda PSC), in which Ninotsminda Oil Company Limited owns a 100% interest. Ninotsminda Oil Company Limited is a wholly owned subsidiary of CanArgo. This PSC covers an area of approximately 27,923 acres (113 Km^{2}), this area, excluding any development area, is subject to a voluntary 25% relinquishment in May 2008;

2. The Nazvrevi and Block XIII Production Sharing Contract (Nazvrevi PSC), covering Blocks XI^{D} and XIII, in which CanArgo (Nazvrevi) Limited owns a 100% interest. CanArgo (Nazvrevi) Limited is a wholly owned subsidiary of CanArgo. This PSC covers an area of approximately acres 388,447 acres (1,572 Km^{2}), however, it is subject to a 50% relinquishment of the remaining contract area less any development areas in August 2008;

3. The Norio (Block XI^{C}) and North Kumisi Production Sharing Agreement (Norio PSA) in which CanArgo Norio Limited currently owns a 100% interest, although this interest may be reduced to 85% should the state oil company, Georgian Oil, exercise an option available to it under the PSA for a limited period following the submission of a field development plan. As a contractor party, Georgian Oil would be liable for all costs and expenses in relation to any interest it may acquire in the PSA. This PSA covers an area of approximately 265,122 acres (1,061 Km^{2}) following a 25% relinquishment in April 2006 and will be subject to a further 50% relinquishment of the remaining contract area less any development area in April 2011;

4. The Block XI^{G} and XI^{H} Production Sharing Contract (Tbilisi PSC), in which CanArgo Norio Limited owns a 100% interest. CanArgo Norio Limited is a wholly owned subsidiary of CanArgo. This PSC covers an area of approximately 119,845 acres (485 Km^{2}), a first relinquishment of 25% of the contract area excluding any development area is due in September 2008 but we are negotiating an extension to this date.

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Until February 16, 2006, we held an interest in the Samgori, Block XI ^{B} Production Sharing Contract (Samgori PSC), in which CanArgo Samgori Limited acquired a 50% interest in 2004 subject to completion of an agreed work program to be completed in part by September 16, 2006 and in full by June 2008, this work program did not commence in time and the Samgori PSC was returned to the previous owner without CanArgo retaining any interest. CanArgo Samgori Limited is a wholly owned subsidiary of CanArgo.

Georgia Location Map

Under production sharing contracts, the contractor party (generally a foreign investor) assumes the risk and provides investment into the project (in the above mentioned contracts, CanArgo through its appropriate subsidiary is a contractor party) and in return is entitled to a share of any petroleum produced which is split into a cost recovery and profit share element. The remaining profit petroleum produced from the project is delivered to the State from which the State will assume, pay and discharge, in the name and on behalf of each contractor party, the contractor party s profit tax liability and all other host State taxes, levies and duties. PSCs are a common form of oil and gas exploration and production contract in many parts of the world.

In Kazakhstan our exploration and development activities centre on the Kyzyloi Production Contract and the Akkulka Exploration Contract. Through our acquisition of 100% of Tethys Petroleum Limited (Tethys or TPL) on June 9, 2005 we increased to 70% our ownership interest in the Kazakhstan based limited liability partnership, BN Munai LLP which owns 100% of the Kyzyloi and Akkulka and Greater Akkulka Contracts. Agreement has now also been reached whereby, subject to any required Kazakh regulatory approvals Tethys, through its wholly owned subsidiary Tethys Kazakhstan Limited (TKL) will acquire the 30% of BNM it does not own in return for 30 million shares in Tethys, and making BNM a wholly owned subsidiary of TKL. TKL s interest in BNM is currently the principal asset of Tethys. Following this share swap there will be approximately 134.7 million shares in Tethys of which CanArgo will own 70 million (52%). The Kyzyloi Gas Field Production Contract covers an area of 70,918 acres (287 Km^2) and is surrounded by the Akkulka Exploration Contract area. In November 2005, BNM acquired a 100% interest in the Greater Akkulka Exploration and Production Contract. This contact, which is for a period of 25 years, with an initial six year exploration period covers an area of approximately 2.78 million acres (11,230Km^2) surrounding the Akkulka area. On the Greater Akkulka Exploration and Production Contract, 20% of the area is to be relinquished at the

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end of the second year (November 23, 2007) with 20% annually thereafter up to the end of the original six year contract.

Oil and Gas Fields

Since 1997, our resources have, through our wholly owned subsidiary Ninotsminda Oil Company Limited, been mainly focused on the development of the Ninotsminda Field and related exploration activities in Georgia, including the Manavi prospect. The Ninotsminda Field covers approximately 3,276 acres (13.26 Km^2) and is located approximately 25 miles (40 Kms) north east of the Georgian capital, Tbilisi. It is adjacent to and east of the Samgori Oil Field, which was Georgia s most productive oil field (we acquired an interest in this Field in early 2004 which we held until February 2006). The Ninotsminda Field was discovered later than the Samgori Field and has experienced substantially less development activity. The Georgian State oil company, Georgian Oil and others, including Ninotsminda Oil Company Limited, have drilled 36 wells in the Ninotsminda Field, of which 11 are currently producing.

We believe the Ninotsminda PSC area both outside of and beneath the currently producing reservoirs of the Field have significant additional exploration and appraisal potential. To date, we have invested and continue to invest substantial funds in exploring the Ninotsminda PSC area including the Manavi prospect where we made an oil discovery in 2003.

In 2003, we acquired interests in certain oil and gas properties in Kazakhstan which included the Kyzyloi Gas Field. A development program is underway on the Kyzyloi Field with the intention of developing a shallow (up to 2,000 feet (600 meters)) gas bearing sandstone reservoir which was discovered, but not developed, during the 1960 s. This Field is located close to the Bukhara-Urals gas trunkline, and to the south of the Bozoi gas storage facility just to the west of the Aral Sea. The Kyzyloi Field covers an area of approximately 70,919 gross acres (287 gross Km^2).

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Kazakhstan Project Location Maps

Other Projects

We have additional exploratory and developmental oil and gas properties and prospects in Georgia and Kazakhstan which we are actively exploring. Previously we had oil and gas interests in Ukraine, but we exited this country in 2004 when we disposed of our single remaining Ukrainian asset, the Bugruvativske Field.

Business Structure

CanArgo is a holding company organized under the laws of the State of Delaware. Our principal product is crude oil, and the sale of crude oil is our principal source of revenue. CanArgo s principal active subsidiaries are as follows:

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Background

Ninotsminda PSC

Our activities at the Ninotsminda Field and on the Manavi prospect are conducted through Ninotsminda Oil Company Limited, a Cypriot corporation (NOC) which became a wholly owned subsidiary of CanArgo in July 2000.

NOC (then named JKX Ninotsminda Limited) obtained its rights to the Ninotsminda Field, including all existing wells, one other field (West Rustavi) and exploration acreage in Block XI ^{E} under a 1996 production sharing contract with Georgian Oil and the State of Georgia (Ninotsminda PSC) which came into effect in February 1996. NOC s rights under the contract expire in December 2019, subject to the possible loss of undeveloped areas prior to that date and a possible extension with regard to developed areas. As such the initial term of the Ninotsminda PSC is until 2019, however, in respect of any development area, if commercial production remains possible beyond 2019 upon giving notice to the State we have an automatic right to extend the contract in respect of such development area for an additional term of 5 years (until 2024) or, if earlier, for the producing life of the development area. Under the Ninotsminda PSC, NOC is required to relinquish at least half of the area then covered by the production sharing contract, but not in portions being actively developed, at five year intervals commencing December 1999. In 1998, these terms were amended with the initial relinquishment being due in 2008 and a reduction in the area to be relinquished at each interval from 50% to 25%.

Under the Ninotsminda PSC, up to 50% of petroleum produced under the contract (Production) is allocated to NOC for the recovery of the cumulative allowable capital, operating and other project costs associated with the Ninotsminda Field and exploration in Block XI ^{E} (cost recovery petroleum). NOC pays 100% of the costs incurred in the project as the sole contractor party under the Ninotsminda PSC. The balance of Production (profit petroleum) is allocated on a 70/30 basis between Georgian Oil as the State representative in the PSC and NOC respectively. While NOC continues to have unrecovered costs, it will receive 65% of Production (cost recovery plus profit petroleum). After recovery of its cumulative capital, operating and other allowable project costs, NOC will receive 30% of Production. Thus, while NOC is responsible for all of the costs associated with the Ninotsminda PSC, it is only entitled to receive 30% of Production after cost recovery. The allocation of a share of Production to Georgian Oil, however, relieves NOC of all obligations it would otherwise have to pay the State of Georgia for taxes, duties and levies related to activities covered by the production sharing contract. Georgian Oil and NOC take their respective shares of oil production in kind, and they market their oil independently, however the intention is to market gas jointly.

Samgori PSC

In April 2004, we acquired a 50% interest in the Samgori PSC in Georgia. This interest was acquired from Georgian Oil Samgori Limited (GOSL), a company wholly owned by Georgian Oil, by one of our subsidiaries, CanArgo Samgori Limited (CSL). Under the terms of the agreement dated January 8, 2004, up to 10 horizontal wells were to be drilled on the Samgori Field as a result of GOSL s earlier acquisition of the contractor s interest in the PSC from the original Contractor party to the Samgori PSC, National Petroleum Limited (NPL). Completion of well S302 in the autumn of 2004, which was funded 100% by us, satisfied our commitment to GOSL under the acquisition agreement. The intention was that the remainder of the drilling program would be funded jointly by CSL and GOSL, the Contractor parties, pro rata their interest in the Samgori PSC. The total cost to us of participating in the whole program, which was due to be completed within 36 months of the commencement of the joint work program, was anticipated to be up to $13,500,000.

On February 17, 2006 we issued a press release announcing that our subsidiary, CSL, was not proceeding with further investment in the Samgori PSC and associated farm-in, and accordingly we terminated our interest in the Samgori PSC with effect from February 16, 2006. The decision by CSL not to proceed with further investment under the current farm-in arrangements was due to the inability of CSL s partner in the project, GOSL, to provide its share of funding to further the development of the Field. We consider that there would have been insufficient time to meet the commitments under the Agreement with NPL and we were not prepared to fund the project, which is not without risk, on a 100% basis without different commercial terms and an extension to the commitment period. It was not possible to negotiate a satisfactory position on either matter. NPL subsequently exercised their right to take back 100% of the Contractor Share in the Samgori PSC from GOSL and, accordingly, effective February 16, 2006 we have withdrawn from the Samgori PSC.

CanArgo Georgia Limited

Pursuant to the terms of CanArgo s PSCs in Georgia, a Georgian not-for-profit company must be appointed as field operator. Until February 2005, there were three such field operating companies, relating to CanArgo s PSCs: Georgian British Oil Company Ninotsminda, Georgian British Oil Company Nazvrevi and Georgian British Oil Company Norio (in respect of both the Norio PSA and the Tbilisi PSC), each of which is 50% owned by a company within the CanArgo group with the remainder owned by Georgian Oil, but with CanArgo having chairmanship of the board and a casting vote. However, on February 1, 2005 Georgian Oil, the State Agency for Regulation of Oil and Gas Resources in Georgia and CanArgo reached agreement on restructuring the field operator companies in our PSCs. A single operator company, CanArgo Georgia Limited, a wholly owned subsidiary company of CanArgo, was appointed the field operator for the Ninotsminda, Nazvrevi, Norio and Tbilisi PSCs. The field operator provides the operating personnel and is responsible for day-to-day operations. CanArgo or a company within the CanArgo group pays the operating company s expenses associated with the development of the fields, and the operating company performs its services on a non-profit basis.

Operations under each of the PSCs are determined by a co-ordinating body (Co-ordinating Committee) composed of members designated by the respective CanArgo company and Georgian Oil, representing the State, with the deciding vote allocated to us. If the State believes that any action proposed by us with which the State disagrees would result in permanent damage to a field or reservoir or in a material reduction in production over the life of a field or reservoir, it may refer the disagreement to a western independent expert for binding resolution. Since we acquired our interest in the PSCs, there has been no such disagreement. Georgian regulatory authorities must approve any drilling sites tentatively selected by us before drilling may commence.

Ninotsminda, Manavi and West Rustavi Production Sharing Contract

Ninotsminda

The Ninotsminda Field was discovered in 1979, with commercial production from the Middle Eocene reservoir established in the same year. When NOC assumed developmental responsibility for the Field in 1996, production was minimal hampered by, we believe, among other factors, a lack of funding, civil strife and utilization of old technology and methods.

The Ninotsminda Field is the easternmost element of an elongate anticline which includes the Samgori and Patardzeuli Fields. The Ninotsminda Field is separated from the Patardzeuli Field to the west by a saddle and a NW-SE trending cross fault. The field structure comprises an elongate anticline which measures 6.2 miles (10 Km) (E-W) by 1.9 miles (3 Km) and has a maximum structural relief of around 2,493 feet (760 meters). The main reservoir horizon is the Middle Eocene which consists of well-bedded deep marine sedimentary rocks eroded from volcanoes. Such rocks typically have low matrix porosity with the gross field wide effective porosity of around 0.1% and permeability in the range of 0.5-10 mD, however, in the Ninotsminda Field there are well developed sub-vertical fractures which provide secondary porosity and permeability of up to 100-500 mD. The reservoir which in the field area is up to 1,640 feet (500 meters) thick is at a depth of 8,530 feet (2,600 meters) below surface to 9,843 feet (3,000 meters) below surface. Production from the Field is facilitated by a strong water drive. The oil accumulation has a gas cap which together form a maximum hydrocarbon column of 1,060 feet (323 meters) thickness, with the gas-oil contact at 4,839 feet (1,475 meters) True Vertical Depth Sub Sea (TVDSS) and the oil-water contact at 5,413 feet (1,650 meters) TVDSS. The oil itself is a high quality sweet crude: 41°API, with just 0.24% sulphur, 4.9% paraffin and 8.7% tar and asphaltene.

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NOC began an immediate rehabilitation of the Ninotsminda Field in 1996 which included repairing and adding perforations to existing wells, acquiring additional seismic data and a limited drilling program. The first new well (named N96) was completed in October 1997 and a second well (N98) was completed in October 1998 which was sidetracked as a horizontal producer in 2000. The N98 horizontal well had produced approximately 435,000 barrels of oil to the end of January 2007.

As a result of this development work, subsequent drilling and the completion of a dynamic reservoir model, it was suggested that a higher level of production could be achieved from the Middle Eocene reservoir from horizontal wells drilled in a preferred orientation so as to intersect the main fracture sets. During 2003, we completed three horizontal sidetrack wells with a total of 3,720 feet (1,134 meters) of horizontal section having been drilled through the reservoir using our own equipment and conventional drilling techniques. Although individual wells tested at rates of over 2,000 barrels of oil per day (bopd) when completed, the wells were put on production at lower rates in accordance with the recommendations of independent petroleum engineering specialists in order to maintain production. However, it has not been possible to maintain production at these levels due to water incursion resulting from, what we believe to be coning of water up the fractures, caused to an extent by, reservoir damage caused by conventional drilling techniques. Nevertheless, the total production to date from these wells amounts to approximately 727,000 barrels of oil and 597 MMcf (16,908 MCM) of natural gas.

Despite the fact that initial production results from the horizontal wells indicated significant improvement, compared to production from offsetting vertical wells, production was not sustainable at the same high levels due

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to, what we believe, being drilled overbalanced with a water-based mud that resulted in highly overbalanced pressures and mud invasion into what is already a low permeability reservoir. In an attempt to address this issue, it was decided to employ under balanced drilling (UBD), as well as drilling with coiled tubing (CT) as these technologies have been combined successfully in the international oil industry to drill undamaged horizontal sections for improved production and exploitation of both oil and gas reservoirs.

In June 2004, we signed a contract with WEUS Holding Inc., a subsidiary of Weatherford International Ltd (Weatherford), for the supply of Under Balanced Coiled Tubing Drilling (UBCTD) services to our projects in Georgia. Under the terms of the contract, Weatherford were to supply and operate a UBCTD unit to be used on a program of up to 14 horizontal well-bores on the Ninotsminda and Samgori Fields (we were party to the Samgori PSC at this time). It was considered that these combined drilling technologies would provide the best way to develop and produce both the Ninotsminda and Samgori Fields.

We planned to drill at least five under balanced horizontal sidetracks on the Ninotsminda Field starting with the N22H well which is located in the east part of the Field where the reservoir is tighter but it is believed to be relatively un-drained. We prepared the well with our own crew which involved sidetracking from the existing well-bore at 8,661 feet (2,640 meters) down to 9,193 feet (2,802 meters) and setting a 4^{1}/2 inch liner. Weatherford commenced operations in December 2004, however technical problems with the Weatherford equipment caused a number of delays which resulted in the UBD not being completed until late February, 2005 with a much shorter than planned section being drilled, and the well not achieving its objective, despite flowing gas at reported high rates through the gas cap section.

Subsequent operations by Weatherford on both N100H2 (an eastern sidetrack to the well where we earlier successfully drilled a conventional horizontal side track to the west) and N49H wells also proved unsuccessful, with Weatherford failing to drill any horizontal section in these wells. Progress was hampered by multiple failures of the downhole motors, other equipment malfunctions and the loss of bottom hole assemblies in the wells. As a result, of the failure of Weatherford to successfully complete any horizontal sidetrack development wells on the Ninotsminda Field using UBCTD technology, Weatherford demobilized its equipment and left Georgia in July 2005.

Despite this lack of success, which we attribute mainly to multiple equipment failures, we still believe that under-balanced technology is an appropriate technology for the development of this type of reservoir. However, due to alternative UBCTD equipment not being available in the short to medium term due to a high demand for oil field equipment and services in general, we decided to continue with our horizontal development and production program and drill at least two additional sidetrack wells with our own equipment.

In October 2005, we successfully sidetracked the N100H2 well having drilled a horizontal section of 1,667 feet (508 meters). A pre-perforated liner was run over a 1,421 foot (433 meters) interval in the horizontal section and was tested at a rate of up to 13.07 MMcf (370 MCM) of gas per day plus 301 barrels of condensate per day. The well is currently choked back as we await completion of repairs by the State owned gas transportation company to the 25 mile (41 Km) pipeline which is planned will deliver the gas from Ninotsminda to the local State-run thermal electricity generating station at Gardabani. A gas supply agreement was concluded in June 2006 with the expectation that sales would commence in September 2006, but repairs to the pipeline have not yet been completed and are unlikely to be completed in time to take delivery of gas during this winter season.

The most recent horizontal sidetrack well to be drilled was the N97H well which we completed in March 2006. It targeted oil volumes un-drained from previous offset area wells and was put on production test following the installation of a slotted liner over a 1,509 feet (460 meters) interval furthest from the heel of the well. The well produced initially with a high water cut, approximately 70%, and an oil rate which peaked at 385 barrels of oil per day (bopd) before declining. Subsequent pressure surveys run with downhole gauges suggested that the N97H well was in communication with the offset N4H well. The most likely assumed scenario was then some of the fracture sets encountered at the end of the N97H well were drained by the N4H well and were hence water filled. Once a very high permeability connection is established with the aquifer, water will flow in preference to any oil filled fractures or matrix of lower permeability.

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On the basis of the test data and due to the fact that the N97H well is approximately 36 feet (11 meters) structurally higher than the N4H well which is still producing oil, we decided to attempt to conduct remedial water isolation. The slotted liner deployed in the horizontal section limited mechanical options for shutting off the toe end of the horizontal section. Previous experience in the field has shown that pulling a liner once set has a very low chance of success due to formation collapse around the liner. Also, a traditional cement isolation was considered to have a low chance of success in a horizontal section, so we opted for a coiled tubing deployed chemical shut-off. Water isolation operations were conducted during the summer months but subsequent production testing showed that the treatment was not successful.

We now plan to set a cement retainer in the solid liner section of the N97H well in order to isolate and abandon the slotted liner part, but this operation has been significantly delayed awaiting delivery of the retainer. The liner through the heel section of the well will then be perforated and the well tested. The build up and heel section of the well are in a crestal location on the field and there has been little previous offset production.

Apart from the Middle Eocene sequence on the Ninotsminda Field there are a number of other reservoirs which contain oil. We have not yet fully evaluated the reserves and economics of production from these zones which include shallower oil reservoirs, the gas cap on the Ninotsminda Field itself or from the hydrocarbon bearing zones below the Middle Eocene. To fully evaluate these zones, further seismic, technical interpretation and drilling will be required.

Manavi & Cretaceous Exploration

Historically, the main focus of oil and gas exploration in Georgia has been directed at the Middle Eocene sequence which provides the reservoir for the Samgori and Ninotsminda Fields. Although the potential of the underlying Cretaceous sequence has long been recognised from limited drilling, surface outcrop (the Cretaceous carbonate interval is believed to be over 1,000 feet (~300 meters) thick and is represented by a high-energy carbonate sequence with good reservoir characteristics) and by analogy to the prolific production from the Cretaceous in nearby Chechnya and Dagestan, this sequence remains very under explored. Structures at this level are deeper; they were less well defined on Soviet era seismic data and technically more difficult to drill hence the general lack of exploration.

Following the acquisition and interpretation of new multi-channel seismic data in the Ninotsminda PSC area in 1998, we identified what we believe to be several large structures at the Cretaceous level, the largest of which is the Manavi prospect. Manavi is located to the east of the Ninotsminda Field and is mapped as a very large, east-west trending anticlinal structure at Top Cretaceous reservoir level, measuring approximately 12 miles by 4 miles (~19 Km by ~5 Km) with 2,950 feet (900 meters) of vertical relief.

The first exploration well, Manavi 11 (M11), drilled on the Manavi structure reached a total depth (TD) of 14,765 feet (4,500 meters) in the Cretaceous in September 2003. The well encountered the Cretaceous limestone target at 14,265 feet (4,348 meters) with over 490 feet (150 meters) of hydrocarbons indicated on wireline logs and with no evidence of an oil-water contact present. On test the M11 well flowed light sweet 34.4ºAPI oil at a visibly significant rate and at a high pressure prior to the test being terminated due to the mechanical failure of the production tubing. Oil was also discovered in the shallower Middle Eocene sequence, but was not tested.

Attempts to recover the damaged tubing from the M11 well were unsuccessful. The well was prepared and subsequently sidetracked using a Saipem S.p.A. (Saipem) Ideco E-2100Az drilling rig equipped with a top-drive drilling system and an oil based mud system provided by Baker-Hughes International (Baker) to control the swelling clays which had proved difficult to drill in the original well.

The Manavi M11Z well reached a TD of 14,994 feet (4,570 meters) in the Cretaceous in October 2005. The well was completed in the Cretaceous using slim-hole drilling technology due to the small size of the casing from which the well was sidetracked. The primary Cretaceous limestone target was encountered at 14,032 feet (4,277 meters) some 230 feet (70 meters) higher than in the original M11 well while the secondary Middle Eocene target zone was penetrated at 13,009 feet (3,965 meters) again significantly higher than in the M11 well. The carbonate section itself was proven to be approximately 980 feet (~300 meters) thick. Drilling data and slim hole wireline logs indicated the presence of hydrocarbons in both the Cretaceous and Middle Eocene target zones, again no oil water contact was identified.

During initial testing operations it emerged that the section of the liner adjacent to the Cretaceous limestone interval may have become differentially stuck probably due to a build up of filter cake on and in the formation during drilling which is in itself indicative of a permeable zone. Although small amounts of oil and gas have been recovered from the well, no significant flow was achieved during the initial testing. Despite efforts to wash the mixture of drilling fluid and carbonate from the well-bore using coiled tubing, it was not possible to clean out the formation and it appears that the Cretaceous limestone formation has been blocked and is not in communication with the well-bore at this time.

Schlumberger well completions experts were consulted who advised that the best techniques with which to re-establish communication with the formation in the well by removing near-well-bore damage is through the application of acid using coiled tubing and, if necessary, perforate. Considering the small diameter of the hole which will limit our ability to optimally test this well, and the fact that the specialist equipment required for this job is both difficult to source and expensive to mobilise for a single operation, we decided to delay completion of this test until after the completion of the planned M12 appraisal well.

Drilling operations at the first appraisal site, M12 using the Saipem rig and Baker oil based mud services commenced on February 9, 2006, however, due to technical problems and having to sidetrack the well meant the well did not reach TD until mid-December 2006. The well was drilled to a depth of 16,762 feet (5,109 meters) in the Cretaceous interval with the top of the carbonate section being penetrated at 14,934 feet (4,552 meters). Significant hydrocarbon shows whilst drilling and wireline logs indicate a potentially significant hydrocarbon column in the well with no definitive presence of a hydrocarbon-water contact. The lower part of the carbonate section where a major gas influx occurred whilst drilling together with the underlying interbedded carbonates and tuffs appear to have the best reservoir characteristics. On setting the production liner, we planned to perform an initial short-term production test of the well prior to demobilizing the rig and then undertake a more comprehensive test as part of a longer-term production test after the site would be cleared and appropriate additional testing equipment installed.

An 886 feet (270 meter) 5   pre-perforated production liner was run over the potential reservoir interval and a production testing string set to test the Cretaceous carbonate and interbedded units. During setting of the test string, the well began flowing and it was necessary to increase the mud weight to control the well whilst the test string was set. Despite the flow and gas observed at surface during drilling operations, the initial testing operations resulted in a pressure increase at surface but with no discernable flow. Subsequent re-perforating of parts of the test interval has resulted in minor flow with gas being flared and black 40.5° API oil collected at surface. However it is considered likely that formation damage has occurred, probably whilst controlling the well during the setting of the test string, with mud penetrating and blocking the formation. Therefore stimulation techniques using acid to clean the well and create conductive pathways from the reservoir to the well-bore and hence bypass any reservoir damage will be required to fully production test the potential of the well. This is a fairly common procedure required in carbonate reservoirs in the area which produce prolifically in the North Caucasus.

On February 8, 2007 we announced that the Saipem drilling rig has now been demobilised from the M12 site and preparations have commenced for the acid stimulation of the reservoir and the resumption of the testing program. FracTech Ltd., a UK company providing independent well completion and stimulation laboratory testing, design and consultancy services, and Schlumberger well completions experts have been consulted and have advised on the chemicals for the test. These chemicals have been sourced in Germany by Schlumberger and are currently on route to Georgia. The stimulation itself will be performed through coiled tubing and this unit is already on site and has commenced cleaning the well in advance of spotting the acid. The acid treatment is expected to commence around the middle of March but a number of acid treatments may be required which will take approximately two to three weeks to complete before the effectiveness of the stimulation can be determined. If the stimulation is successful, we will proceed to test the well with the aim of putting it into early production, however, if further stimulation is required, we would then plan to use hydraulic fracturing techniques in order to fully eliminate the potential formation damage. If the contingent hydraulic fracturing

program is deemed to be required, it will be necessary to bring in specialist equipment to Georgia, and the Company is currently ascertaining the availability of such equipment.

Although management is optimistic about the potential of the Manavi prospect, significant additional drilling and analysis is still required before we will be able to fully evaluate any potential reserves and productive possibilities of this prospect. As part of this analysis, we are also evaluating the technical feasibility of acquiring a 3-D seismic data survey over the Manavi structure.

West Rustavi and Kumisi

The West Rustavi Field is located approximately 25 miles (40 Km) southeast of the Ninotsminda Field. Prior to NOC gaining the Ninotsminda PSC, Georgian Oil drilled ten wells in the West Rustavi Field area, two of which produced oil. The Middle Eocene zone is thinner and less productive in this area than at the Ninotsminda Field and only limited production has taken place from the West Rustavi Field. However, NOC has carried out only very limited workover activity on West Rustavi, and potential may yet exist for further oil production from the Middle Eocene dependant on technical and economic factors. Horizontal drilling may also be appropriate for this deposit. One of the ten wells drilled in the West Rustavi Field was tested in the deeper Cretaceous/Paleocene horizon. This well was tested and produced over 1 MMcf (30 MCM) of gas and 3,500 barrels of water per day, and is interpreted to have tested the down dip extent of a Cretaceous gas deposit named Kumisi. Additional seismic data has been acquired over this structure and the presence of a potentially large prospect has been mapped, with the crestal part being in the Nazvrevi / Block XIII PSC area. The prospect is potentially very significant with the principal risk being closure on the structure. A drilling location for the Kumisi #1 well has been identified within the Nazvrevi PSC area. This prospect is located approximately 7.5 miles (12 Km) southeast of Tbilisi and is close to the domestic gas transportation grid (nearest pipeline approximately 2.2 miles (3.5 Km) (500mm, 10-12 Atm pressure) and a pipeline at 10 miles (16 Km) (700mm, 9-10 Atm), the route of the new South Caucasus gas trunkline from Azerbaijan to Turkey, and is approximately 12.5 miles (20 Km) west of the Gardabani thermal power plant and Rustavi industrial complex.

On March 3, 2006 we announced that our subsidiary, CanArgo (Nazvrevi) Limited (CNZ) had signed a Memorandum of Understanding (MOU) with the Georgian Government which included the terms of a take-or-pay natural gas supply contract relating to gas sales from the Kumisi gas prospect within the Nazvrevi / Block XIII PSC area. The gas supply contract will be with the Georgian State, secured against appropriate bank guarantees, in which CNZ will supply gas from Kumisi based on a pricing formula under which gas is initially supplied at a contract price of $1.56 per Mcf ($55 per MCM), increasing to $2.28 per Mcf ($80 per MCM) by the tenth contract year, after which escalation will be based on European Union heavy fuel oil price changes. The contract will be for the entire field life. However, after the tenth year, CNZ has the option of selling to third parties if the price obtained is 10% above the contract price at that time.

This MOU became effective in February 2007 on receipt of regulatory approval and a drilling permit and CNZ commenced drilling the Kumisi #1 well on February 7, 2006. The well which is being drilled with CanArgo Rig #2 is expected to reach total depth of 12,140 feet (3,700 meters) in the Cretaceous by late June. Surface casing has been set at a depth of 1,004 feet (306 meters) and the well is currently drilling ahead at approximately 4,921 feet (1,500 meters) in the Middle Eocene.

In addition to the horizons discussed above, seismic and well data are currently being interpreted to identify further prospects in the Ninotsminda area at several different stratigraphic levels.

ITEM 1A. RISK FACTORS

Reference is hereby made to the Section entitled CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS with respect to certain qualifications regarding the following information. The risks described below are not the only ones facing the Company. Additional risks not presently known to us or that we currently deem immaterial may also impair our business operations and adversely affect the price of our shares.

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RISKS ASSOCIATED WITH OUR BUSINESS AND BUSINESS OPERATIONS.

We Have Experienced Recurring Losses.

For the fiscal years ended December 31, 2006, 2005, 2004, 2003, and 2002, we recorded net losses of $60,540,851, $12,335,314, $4,757,000, $7,322,000, and $5,328,000 respectively, and have an accumulated deficit of $177,742,357 as at December 31, 2006. Impairments of oil and gas properties, ventures and other assets in 2006 included writedowns of $38,400,000 in our carrying value of the Ninotsminda Field. The Company may never achieve or maintain profitability. The Company will need to generate significant revenues to achieve and maintain profitability. The Company cannot guarantee that it will be able to generate these revenues, and it may never achieve profitability.

Our Ability To Pursue Our Activities Is Dependent On Our Ability To Generate Cash Flows.

Our ability to continue to pursue our principal activities of acquiring interests in and developing oil and gas fields is dependent upon generating funds from internal sources, external sources and, ultimately, maintaining sufficient positive cash flows from operating activities.

Our financial statements have been prepared in accordance with U.S. GAAP, which contemplates continuation of the Company as a going concern. The Company incurred net losses from continuing operations to common stockholders of approximately $61,214,000, $12,938,000 and $6,262,000 for the years ended December 31, 2006, 2005 and 2004 respectively. These net losses included non-cash charges related to depreciation and depletion, impairments, loan interest, amortization of debt discount and stock-based compensation of approximately $48,653,000, $6,928,000 and $5,104,000 for the years ended December 31, 2006, 2005 and 2004 respectively.

In the years ended December 31, 2006 and 2005, the Company s revenues from its Georgian operations did not cover the costs of its operations. At December 31, 2006 the Company had unrestricted cash and cash equivalents available for general corporate use or for use in the Georgian operations of approximately $14,780,000. In 2006 the Company experienced a net cash outflow from operations of approximately $17,883,000 in Georgia. In addition, the Company has a planned capital expenditure budget in 2007 of approximately $5,200,000 in Georgia. In the event that the exploration and development wells currently undergoing or waiting to undergo production testing in Georgia fail to produce enough commercially available quantities of oil and or gas, the Company may not have sufficient working capital and may have to delay or suspend its capital expenditure plans and possibly make cutbacks in its operations. There are no assurances the Company could raise additional sources of equity financing and because of the covenants contained in the Senior Secured Notes (see Note 11 of the consolidated financial statements) the Company is restricted from incurring additional debt obligations unless it receives consent from at least 51% of the noteholders, which cannot be assured.

The Company believes that if it is able to successfully complete the Manavi 12 well in the second quarter such that a significant quantity of oil flows are produced, that it will be able to raise additional debt and or equity funds in order to continue operations and to properly develop the Manavi field and continue working on the Norio and Ninotisminda fields.

In October 2006, CanArgo Limited, a wholly owned subsidiary of the Company, converted all of its outstanding loans due from Tethys into 69,999,900 shares of Tethys share capital. In February 2007 we announced that TPL had completed a private placement with a limited group of private investors raising gross proceeds of approximately $17.35 million, by issuing in total approximately 34.7 million new ordinary shares in TPL, these representing approximately 33% of the issued and outstanding share capital of TPL, and with us retaining our 70,000,000 shares in TPL, these representing the remaining 67%. Under the terms of previous subordinated debt issuances by the Company (see Note 11 of the consolidated financial statements), CanArgo Energy Corporation is restricted from using any of the cash held by Tethys or its subsidiaries for general corporate use nor is it able to use those funds for the drilling program in Georgia so long as there is principal outstanding under those notes. Under the terms of the Shareholders Agreement entered into with the new private investors, TPL is subject to certain positive and negative covenants which require the consent of the holders of not less than 75% of the ordinary shares in issue in TPL from time to time (the Shareholder Majority). The Agreement also outlines certain provisions in relation to the conduct of the TPL business and provided that the intention of TPL, CanArgo Limited and the Investors is to use their reasonable endeavors to work towards a listing of TPL as soon as practicable, subject to (i) the financial and commercial circumstances of TPL, and the pre-money valuation of TPL prior to the listing being acceptable to the Shareholder Majority; and (ii) the terms and amounts (if any) raised by TPL on such listing being acceptable to the board of TPL. With the completion of the private placement in February 2007, we have fully funded the currently planned budget for our operating and development expenditure in Kazakhstan for 2007.

Consequently, the aforementioned items raise substantial doubt about the Company s ability to continue as a going concern.

The Company s ability to continue as a going concern is dependent upon raising capital through debt and equity financing on terms desirable to the Company. If the Company is unable to obtain additional funds when they are required or if the funds cannot be obtained on terms favorable to the Company, management may be required to delay, scale back or eliminate its well development program or license third parties to develop or market products that the Company would otherwise seek to develop or market itself, or even be required to relinquish its interest in the properties or in the extreme situation, cease operations. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Our Current Operations Are Dependent On the Success of Our Georgian Exploration Activities and Our Activities on the Ninotsminda Field.

To date we have directed substantially all of our efforts and most of our available funds to the development of the Ninotsminda Field in the Kura Basin in the eastern part of Georgia, appraisal of the Manavi oil discovery, and exploration in that area and some ancillary activities in the Kura Basin area. This decision is based on management s assessment of the promise of the Kura Basin area. However, our focus on the Ninotsminda Field has over the past several years resulted in overall losses for us. We cannot assure investors that the exploration and development plans for the Ninotsminda Field will be successful. For example, the Ninotsminda Field may not produce sufficient quantities of oil and gas and at sufficient rates to justify the investment we have made and are planning to make in the Field, and we may not be able to produce the oil and gas at a sufficiently low cost or to market the oil and gas produced at a sufficiently high price to generate a positive cash flow and a profit. Our Georgian exploration program, particularly in the Manavi and Norio areas, is an important factor for future success, and this program may not be successful, as it carries substantial risk. See Our oil and gas activities involve risks, many of which are beyond our control below for a description of a number of these potential risks

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and losses. In accordance with customary industry practices, we maintain insurance against some, but not all, of such risks and some, but not all, of such losses. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial condition and results of operations.

Our Operation Of The Ninotsminda Field Is Governed By a Production Sharing Contract Which May Be Subject To Certain Legal Uncertainties.

Our principal business and assets are derived from production sharing contracts in Georgia. The legislative and procedural regimes governing production sharing agreements and mineral use licenses in Georgia have undergone a series of changes in recent years resulting in certain legal uncertainties. Our production sharing agreements and mineral use licenses, entered into prior to the introduction in 1999 of a new Petroleum Law governing such agreements have not, as yet, been amended to reflect or ensure compliance with current legislation. As a result, despite references in the current legislation grandfathering the terms and conditions of our production sharing contracts, conflicts between the interpretation of our production sharing contracts and mineral use licenses and current legislation could arise. Such conflicts, if they arose, could cause an adverse effect on our rights under the production sharing contracts.

We May Encounter Difficulties In Enforcing Our Title To Our Properties.

Since all of our oil and gas interests are currently held in countries where there is currently no private ownership of oil and gas in place, good title to our interests is dependent on the validity and enforceability of the governmental licenses and production sharing contracts and similar contractual arrangements that we enter into with government entities, either directly or indirectly. As is customary in such circumstances, we perform a minimal title investigation before acquiring our interests, which generally consists of conducting due diligence reviews and in certain circumstances securing written assurances from responsible government authorities or legal opinions. We believe that we have satisfactory title to such interests in accordance with standards generally accepted in the crude oil and natural gas industry in the areas in which we operate. Our interests in properties are subject to royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, none of which we believe materially interferes with the use of, or affects the value of, such interests. However, as is discussed elsewhere, there is no assurance that our title to its interests will be enforceable in all circumstances due to the uncertain nature and predictability of the legal systems in some of the countries in which we operate.

We Will Require Additional Funds To Implement Our Long-Term Oil And Gas Development Plans.

It will take many years and substantial cash expenditures to develop fully our oil and gas properties. We generally have the principal responsibility to provide financing for our oil and gas properties and ventures. Accordingly, we may need to raise additional funds from outside sources in order to pay for project development costs. We may not be able to obtain that additional financing. If adequate funds are not available, we will be required to scale back or even suspend our operations or such funds may only be available on commercially unattractive terms. The carrying value of the Ninotsminda Field may not be realized unless additional capital expenditures are incurred to develop the Field. Furthermore, additional funds will be required to pursue exploration activities on our existing undeveloped properties. While expected to be substantial, without further exploration work and evaluation the amount of funds needed to fully develop all of our oil and gas properties cannot at present be quantified.

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We May Be Unable To Finance Our Oil And Gas Projects.

Our long term ability to finance most of our present oil and gas projects and other ventures according to present plans is dependent upon obtaining additional funding. An inability to obtain financing in the future could require us to scale back or abandon part or all of our future project development, capital expenditure, production and other plans. The availability of equity or debt financing to us or to the entities that are developing projects in which we have interests is affected by many factors, including:

- world and regional economic conditions;
- the state of international relations;
- the stability and the legal, regulatory, fiscal and tax policies of various governments in the areas in which we have or intend to have operations;
- fluctuations in the world and regional price of oil and gas and in interest rates;
- the outlook for the oil and gas industry in general and in areas in which we have or intend to have operations; and
- competition for funds from possible alternative investment projects.

Potential investors and lenders will be influenced by their evaluations of us and our projects, including their technical difficulty, and comparison with available alternative investment opportunities.

Our Operations May Be Subject To The Risk Of Political Instability, Civil Disturbance And Terrorism.

Our principal oil and gas properties and activities are in Georgia and, currently, to a lesser extent in Kazakhstan, which are both located in the former Soviet Union. Operation and development of our assets are subject to a number of conditions endemic to former Soviet Union countries, including political instability. The present governmental arrangements in countries of the former Soviet Union in which we operate were established relatively recently, when they replaced communist regimes. If they fail to maintain the support of their citizens, other institutions, including a possible reversion to totalitarian forms of government, could replace these governments. As recent developments in Georgia have illustrated, the national governments in these countries often must deal, from time to time, with civil disturbances and unrest which may be based on religious, tribal and local and regional separatist considerations. Further, relations between Georgia and the Russian Federation have involved periods of political tension. Our operations typically involve joint ventures or other participatory arrangements with the national government or state-owned companies. The production sharing contract covering the Ninotsminda Field is an example of such arrangements. As a result of such dependency on government participants, our operations could be adversely affected by political instability, terrorism, changes in government institutions, personnel, policies or legislation, or shifts in political power. There is also the risk that governments could seek to nationalize, expropriate or otherwise take over our oil and gas properties either directly or through the enactment of laws and regulations which have an economically confiscatory result. We are not insured against political or terrorism risks because management deems the premium costs of such insurance to be currently prohibitively expensive.

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We Face The Risk Of Social, Economic And Legal Instability In The Countries In Which We Operate.

The political institutions of the countries that were a part of the former Soviet Union have become more fragmented, and the economic institutions of these countries have converted to a market economy from a planned economy. New laws have been introduced, and the legal and regulatory regimes in such regions may be vague, containing gaps and inconsistencies, and are subject to amendment. Application and enforceability of these laws may also vary widely from region to region within these countries. Due to this instability, former Soviet Union countries are subject to certain additional risks including the uncertainty as to the enforceability of contracts. Social, economic and legal instability have accompanied these changes due to many factors which include:

- low standards of living;
- high unemployment;
- under-developed and changing legal and social institutions; and
- conflicts within and with neighbouring countries.

This instability could make continued operations difficult or impossible. Georgia has democratically elected a President following a popular revolt against the previous administration in November 2003 and has successfully quelled a potential separatist uprising in one of its regions. Although the new administration has made public statements supporting foreign investment in Georgia, and has provided specific written support for our activities, there can be no guarantee that this will continue, or that these changes will not have an adverse affect on our operations. There are also some separatist areas within Georgia that receive support from the Russian Federation that may cause instability and potentially affect our activities.

We Face An Inadequate Or Deteriorating Infrastructure In The Countries In Which We Operate.

Countries in the former Soviet Union often either have underdeveloped infrastructures or, as a result of shortages of resources, have permitted infrastructure improvements to deteriorate. The lack of necessary infrastructure improvements can adversely affect operations. For example, we have, in the past, suspended drilling and testing procedures due to the lack of a reliable power supply.

We May Encounter Currency Risks In The Countries In Which We Operate.

Payment for oil and gas products sold in former Soviet Union countries may be in local currencies. Although we currently sell our oil principally for U.S. dollars, we may not be able to continue to demand payment in hard currencies in the future. Most former Soviet Union country currencies are presently convertible into U.S. dollars, but there is no assurance that such convertibility will continue. Even if currencies are convertible, the rate at which they convert into U.S. dollars is subject to fluctuation. In addition, the ability to transfer currencies into or out of former Soviet Union countries may be restricted or limited in the future. We may enter into contracts with suppliers in former Soviet Union countries to purchase goods and services in U.S. dollars. We may also obtain from lenders credit facilities or other debt denominated in U.S. dollars. If we cannot receive payment for oil and oil products in U.S. dollars and the value of the local currency relative to the U.S. dollar deteriorates, we could face significant negative changes in working capital.

We May Encounter Tax Risks In The Countries In Which We Operate.

Countries may add to or amend existing taxation policies in reaction to economic conditions including state budgetary and revenue shortfalls and political considerations. Since we are dependent on international operations, specifically those in Georgia, we may be subject to changing taxation policies including the possible imposition of confiscatory excess profits, production, remittance, export and other taxes. While we are not aware of any recent or proposed tax changes which could materially adversely affect our operations, such changes could occur although we have negotiated economic stabilization clauses in our production sharing contracts in Georgia and all current taxes are payable from the State s share of petroleum produced under the production sharing contracts.

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We have identified material weaknesses in our internal controls over financial reporting which, if not remediated, may adversely affect our ability to timely and accurately meet our financial reporting responsibilities.

We identified a number of material weaknesses in our internal controls over financial reporting as of December 31, 2006. Our management, in consultation with our audit committee, is continually reviewing the most cost effective way to address material weaknesses and deficiencies identified. Our failure to complete this remediation process may adversely affect our ability to accurately report our financial results in a timely manner.

Risks Associated with our Industry.

We May Be Required To Write-Off Unsuccessful Properties And Projects.

In order to realize the carrying value of our oil and gas properties and ventures, we must produce oil and gas in sufficient quantities and then sell such oil and gas at sufficient prices to produce a profit. We have a number of unevaluated oil and gas properties. The risks associated with successfully developing unevaluated oil and gas properties are even greater than those associated with successfully continuing development of producing oil and gas properties, since the existence and extent of commercial quantities of oil and gas in unevaluated properties have not been established. We could be required in the future to write-off our investments in additional projects, including the Ninotsminda Field project, if such projects prove to be unsuccessful.

Our Oil And Gas Activities Involve Risks, Many Of Which Are Beyond Our Control.

Our exploration, development and production activities are subject to a number of factors and risks, many of which may be beyond our control. We must first successfully identify commercial quantities of oil and gas, which is inherently subject to many uncertainties. Thereafter, the development of an oil and gas deposit can be affected by a number of factors which are beyond the operator s control, such as:

- unexpected or unusual geological conditions;
- the recoverability of the oil and gas on an economic basis;
- the availability of infrastructure and personnel to support operations;
- labor disputes;
- local and global oil prices; and
- government regulation and legal and political uncertainties.

Our activities can also be affected by a number of hazards, such as:

- natural phenomena, such as bad weather and earthquakes;
- operating hazards, such as fires, explosions, blow-outs, pipe failures and casing collapses; and
- environmental hazards, such as oil spills, gas leaks, ruptures and discharges of toxic gases.

Any of these factors or hazards could result in damage, losses or liability for us. There is also an increased risk of some of these hazards in connection with operations that involve the rehabilitation of fields where less than optimal practices and technology were employed in the past, as was often the case in the countries that were part of the former Soviet Union. We do not purchase insurance covering all of the risks and hazards or all of our potential liability that are involved in oil and gas exploration, development and production.

We May Have Conflicting Interests With Our Partners.

Joint venture, acquisition, financing and other agreements and arrangements must be negotiated with independent third parties and, in some cases, must be approved by governmental agencies. These third parties generally have objectives and interests that may not coincide with ours and may conflict with our interests. Unless we are able to compromise these conflicting objectives and interests in a mutually acceptable manner, agreements and arrangements with these third parties will not be consummated. We may not have a majority of the equity in the entity that is the licensed developer of some projects that we may pursue in the countries that were a part of the former Soviet Union, even though we may be the designated operator of the oil or gas field. In these circumstances, the concurrence of co-venturers may be required for various actions. Other parties influencing the timing of events may have priorities that differ from ours, even if they generally share our objectives. Demands by or expectations of governments, co-venturers, customers, and others may affect our strategy regarding the various projects. Failure to meet such demands or expectations could adversely affect our participation in such projects or our ability to obtain or maintain necessary licenses and other approvals.

Our Operating Direct And Indirect Subsidiaries And Joint Ventures Require Governmental Registration.

Operating entities in various foreign jurisdictions must be registered by governmental agencies, and production licenses and contracts for the development of oil and gas fields in various foreign jurisdictions must be granted by governmental agencies. These governmental agencies generally have broad discretion in determining whether to take or approve various actions and matters. In addition, the policies and practices of governmental agencies may be affected or altered by political, economic and other events occurring either within their own countries or in a broader international context.

We Are Affected By Changes In The Market Price Of Oil And Gas.

Prices for oil and natural gas and their refined products are subject to wide fluctuations in response to a number of factors which are beyond our control, including:

- global and regional changes in the supply and demand for oil and natural gas;
- actions of the Organization of Petroleum Exporting Countries;
- weather conditions;
- domestic and foreign governmental regulations;
- the price and availability of alternative fuels;
- political conditions and terrorist activity in the Middle East, Central Asia and elsewhere; and
- overall global and regional economic conditions.

A reduction in oil prices can affect the economic viability of our operations. There can be no assurance that oil prices will be at a level that will enable us to operate at a profit. We may also not benefit from rapid increases in oil prices as the market for the levels of crude oil produced in Georgia by Ninotsminda Oil Company Limited can in such an environment be relatively inelastic. Contract prices are often set at a specified price determined with reference to world market prices (often based on the average of a number of quotations for a marker crude including Dated Brent Mediterranean or Urals Mediterranean at the time of sale) subject to appropriate discounts for transportation and other charges which can vary from contract to contract.

Our Actual Oil And Gas Production Could Vary Significantly From Reserve Estimates.

Estimates of oil and natural gas reserves and their values by petroleum engineers are inherently uncertain. These estimates are based on professional judgments about a number of elements:

the amount of recoverable crude oil and natural gas present in a reservoir;

the costs that will be incurred to produce the crude oil and natural gas; and

the rate at which production will occur.

Reserve estimates are also based on evaluations of geological, engineering, production and economic data. The data can change over time due to, among other things:

additional development activity;

evolving production history; and

changes in production costs, market prices and economic conditions.

As a result, the actual amount, cost and rate of production of oil and gas reserves and the revenues derived from sale of the oil and gas produced in the future will vary from those anticipated in the reports on the oil and gas reserves prepared by independent petroleum consultants at any given point in time. The magnitude of those variations may be material. The rate of production from crude oil and natural gas properties declines as reserves are depleted. Except to the extent we acquire additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, identify additional productive zones in existing wells or secondary recovery reserves, our proved reserves will decline as reserves are produced. Future crude oil and natural gas production is therefore highly dependent upon our level of success in replacing depleted reserves.

Our Oil And Gas Operations Are Subject To Extensive Governmental Regulation.

Governments at all levels, national, regional and local, regulate oil and gas activities extensively. We must comply with laws and regulations which govern many aspects of our oil and gas business, including:

exploration;

development;

production;

refining;

marketing;

transportation;

occupational health and safety;

labor standards; and

environmental matters.

We expect the trend towards more burdensome regulation of our business to result in increased costs and operational delays. This trend is particularly applicable in developing economies, such as those in the countries that were a part of the former Soviet Union where we have our principal operations. In these countries, the evolution towards a more developed economy is often accompanied by a move towards the more burdensome regulations that typically exist in more developed economies.

We Face Significant Competition.

The oil and gas industry, including the refining and marketing of crude oil products, is highly competitive. Our competitors include integrated oil and gas companies, government owned oil companies, independent oil and gas companies, drilling and income programs, and wealthy individuals. Many of our competitors are large, well-established, well-financed companies. Because of our small size and lack of financial resources, we may not be able to compete effectively with these companies.

Our Profitability May Be Subject To Changes In Interest Rates.

Our profitability may also be adversely affected during any period of unexpected or rapid increase in interest rates. While we currently have only limited amounts of long term debt, increases in interest rates may adversely affect our ability to raise debt capital to the extent that our income from operations will be insufficient to cover debt service.

Risks Associated with our Stock.

Limited Trading Volume In Our Common Stock May Contribute To Price Volatility.

Our common stock is listed for trading on the Oslo Stock Exchange (OSE) in Norway, and on the American Stock Exchange (AMEX) in New York. During the year ended December 31, 2006, the average daily trading volume for our common stock on the OSE was 3,055,728 shares and 881,919 shares on the AMEX both as reported by Yahoo© and the closing price of our stock during such period ranged from a low of NOK 3,97 and $0.62 to a high of NOK 10.20 and $1.66 on the OSE and AMEX, respectively, as reported by Yahoo©. As a relatively small company with a limited market capitalization, even if our shares are more widely disseminated, we are uncertain as to whether a more active trading market in our common stock will develop. As a result, relatively small trades may have a significant impact on the price of our common stock.

The Price Of Our Common Stock May Be Subject To Wide Fluctuations.

The market price of our common stock could be subject to wide fluctuations in response to quarterly variations in our results of operations, changes in earnings estimates by analysts, changing conditions in the oil and gas industry or changes in general market, economic or political conditions.

We Do Not Anticipate Paying Cash Dividends In The Foreseeable Future.

We have not paid any cash dividends to date on the common stock and there are no plans for such dividend payments in the foreseeable future.

We Have A Significant Number Of Shares Eligible For Future Sale.

At March 9, 2007, we had 238,487,390 shares of common stock outstanding of which 53,482,484 shares were held by affiliates. In addition, at March 9, 2007, we had 45,270 shares issuable upon exchange of CanArgo Oil & Gas Inc. Exchangeable Shares without receipt of further consideration; 9,276,000 shares of common stock subject to outstanding options granted under certain stock option plans (of which 8,145,000 shares were vested at March 9, 2007); 26,800,000 shares issuable upon exercise of outstanding warrants; up to 8,568,667 shares of common stock reserved for issuance under our existing option plans; up to 50,965,277 shares reserved for issuance in connection with certain existing contractual arrangements, including 10,000,000 shares upon conversion of the 12% Subordinated Convertible Guaranteed Note due June 28, 2010 (12% Subordinated Notes) and 13,000,000 shares upon conversion of the Senior Subordinated Convertible Guaranteed Notes due September 1, 2009 (Subordinated Notes) and 27,777,777 shares upon conversion of the Company s Senior Secured Notes due July 25, 2009 (Senior Secured Notes). All of the shares of common stock held by affiliates are restricted or control securities under Rule 144 promulgated under the Securities Act of 1933, as amended. The shares of common stock issuable upon exercise of the stock options have been registered under the Securities Act. In addition, the 63,228,645 shares issued and issuable pursuant to contractual arrangements, including under the Subordinated Notes and Senior Secured Notes, are subject to certain registration rights and, therefore, will be eligible for resale in the public market after registration statements covering such shares. Sales of shares of common stock under Rule 144 or pursuant to a registration statement could have a material adverse effect on the price of the common stock and could impair our ability to raise additional capital through the sale of our equity securities.

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Our Ability To Incur Additional Indebtedness Is Restricted Under the Terms of the 12% Subordinated Notes, the Subordinated Notes and Senior Secured Notes.

Pursuant to the terms of the Note Purchase Agreements entered into by and between CanArgo and the purchasers of the 12% Subordinated, Subordinated and Senior Secured Notes, we may not incur future indebtedness or issue additional senior or *pari passu* indebtedness, except with the prior consent of the beneficial holders of at least 51% (in the case of the Senior Secured Notes) or 50% (in the case of the Subordinated or 12% Subordinated Notes) of the outstanding principal amount of each such Notes or in limited permitted circumstances. The definition of indebtedness in each of the Note Purchase Agreements encompasses all customary forms of indebtedness, including, without limitation, liabilities for deferred consideration, liabilities for borrowed money secured by any lien or other specified security interest (except permitted liens), liabilities in respect of letters of credit or similar instruments (excluding letters of credit which are 100% cash collateralized) and guarantees in relation to such forms of indebtedness (excluding parent company guarantees provided by CanArgo in respect of the indebtedness or obligations of any of our subsidiaries under any Basic Documents (as defined in each of the Note Purchase Agreements).

Our Ability To Make Future Stock Issuances, the Terms of the 12% Subordinated Notes, the Subordinated Notes and Senior Secured Notes And The Provisions Of Delaware Law Could Have Anti-Takeover Effects.

Our board of directors may at any time issue additional shares of preferred stock and common stock without any prior approval by the stockholders, which might impair or impede a third party from making an offer to acquire us. Holders of outstanding shares have no right to purchase a pro rata portion of additional shares of common or preferred stock issued by us. Further, under the terms of the 12% Subordinated Notes, the Subordinated Notes and Senior Secured Notes, in the event of a Change of Control or a Control Event we are required to offer to prepay the Notes which might also dissuade a third party from making an acquisition offer. See Note 11 of the consolidated financial statements for the definition of Change of Control and Control Event . In addition, the provisions of Section 203 of the Delaware General Corporation Law, to which we are subject, places certain restrictions on third parties who seek to effect a business combination with a company opposed by our board of directors.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

Not applicable.

ITEM 2. PROPERTIES.

Production History

Ninotsminda

The Ninotsminda Field was discovered and initial development began in 1979. Current average gross field production for the month of January, 2007 was approximately 485 bopd. Gross and net production from the Ninotsminda Field for the past three years was as follows:

	Oil (Barrels)		Gas (mcf)	
Year Ended December 31,	**Gross**	**Net (PSC Entitlement)(1)**	**Gross**	**Net (PSC Entitlement)(1)**
2006	178,474	116,008	20,093	13,061
2005	184,952	120,219	71,241	46,307
2004	370,176	241,131	65,066	42,293

(1) PSC Entitlement Volumes attributed to CanArgo are calculated using the economic interest method applied to the terms of the production sharing contract. PSC Entitlement Volumes are those produced volumes which, through the production sharing contract, accrue to the benefit of the contractor party after deduction of Georgian Oil s share which includes all Georgian taxes, levies and duties. Ninotsminda Oil Company Limited (NOC) owns 100% of the contractor s interest in the PSC. As a result of CanArgo s interest in NOC, these volumes

accrue to the benefit of CanArgo for the recovery of capital, repayment of operating costs and share of profit.

Samgori

Between April 2004 and February 16, 2006 we had a 50% interest in the Samgori (Block XI ^{B}) Production Sharing Contract (Samgori PSC) in Georgia, we terminated our interest with effect from February 16, 2006. The gross and net production for the period in which we had an interest in the Samgori PSC including the period January 1, 2006 to February 16, 2006 was as follows:

	Oil (Barrels)		
Year Ended December 31,	**Gross**	**Net (PSC Entitlement)(2)**	**CSL Net Share**
2006 (two months)	10,226	7,669	3,835
2005	166,298	124,723	62,362
2004 (nine months)	152,169	114,127	57,063

(2) PSC Entitlement Volumes attributed to CanArgo are calculated using the economic interest method applied to the terms of the production sharing contract. PSC Entitlement Volumes are those produced volumes which, through the production sharing contract, accrue to the benefit of the contractor parties after deduction of Georgian Oil s share which includes all Georgian taxes, levies and

duties. CanArgo Samgori Limited (CSL) owned 50% of the contractor s interest in the PSC. As a result of CanArgo s interest in CSL, these volumes accrued to the benefit of CanArgo for the recovery of capital, repayment of operating costs and share of profit.

We ceased to have an interest in this project on February 16, 2006.

Productive Wells and Acreage

The following table summarizes as of December 31, 2006, 2005 and 2004 with respect to NOC the number of productive oil and gas wells and the total developed acreage for the Ninotsminda Field. Such information has been presented on a gross basis, representing our 100% interest in NOC.

	Gross	
	Number of Wells	**Acres**
2006	11	492
2005	11	492
2004	11	492

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On December 31, 2006, there were no other productive wells or developed acreage within the Ninotsminda PSC area except for one gross well on the West Rustavi Field which was shut-in at that date.

The only other productive wells or developed acreage on any of our other Georgian properties were within the Samgori PSC area on the Samgori Field. This information below as of December 31, 2006, 2005 and 2004 is presented on a net basis representing our 100% interest in CSL which in turn had a 50% interest in the Samgori PSC. Our interest in the Samgori PSC was terminated with effect from February 16, 2006.

	Net	
	Number of Wells	Acres
2006		
2005	11.5	950
2004	11.5	950

Reserves

<u>*Ninotsminda Field, Georgia*</u>

The following table summarizes net hydrocarbon reserves for the Ninotsminda Field in Georgia. This information is derived from a report dated as of January 1, 2007 prepared by Oilfield Production Consultants (OPC), independent petroleum consultants headquartered in London, England. This report is available for inspection at our principal executive offices during regular business hours. The reserve information in the table below has also been filed with the Oslo Stock Exchange.

Oil Reserves	**Oil Reserves Gross (Million Barrels)**	**PSC Entitlement Volumes(1) (Million Barrels)**
Proved Developed	1.811	1.177
Proved Undeveloped	1.568	1.019
Total Proven	3.379	2.196

Gas Reserves	**Gas Reserves - Gross (Billion Cubic Feet)**	**PSC Entitlement Volumes(1) (Billion Cubic Feet)**
Proved Developed	1.885	1.225
Proved Undeveloped	.923	0.600
Total Proven	2.808	1.825

(1) PSC Entitlement Volumes attributed to CanArgo are calculated using

the economic interest method applied to the terms of the production sharing contract. PSC Entitlement Volumes are those produced volumes which, through the production sharing contract, accrue to the benefit of the respective contractor parties after deduction of Georgian Oil s share which includes all Georgian taxes, levies and duties. As a result of CanArgo s interest in NOC, these volumes

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accrue to the benefit of CanArgo for the recovery of capital, repayment of operating costs and share of profit.

No independent reserves have been assessed for the West Rustavi Field.

Exploration and Development Wells

The following table summarizes as of December 31, 2006 the number of exploration and development oil and gas wells in progress. Such information has been presented on a gross basis, representing our 100% interest in these wells.

	Exploration	Development
Ninotsminda Field	2	
Norio Field	1	
Nazvrevi Field	1	
	4	

The following table summarizes as of December 31, 2006, 2005 and 2004, the total number of dry exploration oil and gas wells drilled. The information has been represented on a gross basis, representing our 100% interest in this well.

	2006	2005	2004
Ninotsminda Field	1	1	1
	1	1	1

The following table summarizes as of December 31, 2006, 2005 and 2004, the total number of dry development oil and gas wells drilled. The information has been presented on a gross basis representing our 100% interest in this well. Our interest in the Samgori PSC was terminated with effect from February 16, 2006.

	2006	2005	2004
Samgori Field*	1	1	1
	1	1	1

* CSL 100% funded a development well drilled on the Samgori complex in 2004.

The following table summarizes as of December 31, 2006, 2005 and 2004, the total number of completed wells that flowed commercial quantities of oil and gas. The information has been represented on a gross basis, representing our 100% interest in these wells.

	2006	2005	2004
Ninotsminda Field	8	8	6
	8	8	6

Kyzyloi and Akkulka Gas Fields in Kazakhstan

The following table summarizes net hydrocarbon reserves for the Kyzyloi and Akkulka Gas Fields in Kazakhstan. This information is also derived from a report dated as of January 1, 2007 prepared by Oilfield Production Consultants (OPC), independent petroleum consultants headquartered in London, England. This report is available for inspection at our principal executive offices during regular business hours. The reserve information in the table below has also been filed with the Oslo Stock Exchange.

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Gas Reserves	Gas Reserves - Gross (Billion Cubic Feet)	Gas Reserves - Net(1) (Billion Cubic Feet)
Proved Undeveloped	30.340	30.340
Total Proven	30.340	30.340

(1) TPL through its 100% owned subsidiary Tethys Kazakhstan Limited (TKL) currently holds 70% ownership rights in BN Munai LLP, a Kazakh registered limited liability partnership that has the 100% rights to the Kyzyloi field. Under a loan agreement with BN Munai LLP, TKL will take 100% of the net cash flow of the Kyzyloi development until its loan is repaid. This loan is currently in excess of net cash flows generated from the production of gross proven reserves.

Proved reserves are those reserves estimated as recoverable under current technology and existing economic conditions from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economically and technically successful in the subject reservoir. Proved reserves include proved developed reserves (producing and non-producing reserves) and proved undeveloped reserves.

Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive wells that are reasonably certain of production when drilled.

Uncertainties exist in the interpretation and extrapolation of existing data for the purposes of projecting the ultimate production of oil from underground reservoirs and the corresponding future net cash flows associated with that production. The estimating process requires educated decisions relating to the evaluation of all available geological, engineering and economic data for each reservoir. The amount and timing of cost recovery is a function of oil and gas prices which can fluctuate significantly over time. The oil price used in the Ninotsminda Field report by OPC as of January 1, 2007 was $51.50 per barrel based on the Brent spot price per barrel at year end less $8.50 per barrel discount, in line with CanArgo s most recent contractual arrangement. The net gas price used in the Ninotsminda Field report ranged from $0.71 to $1.71 per Mcf in line with CanArgo s most recent contractual arrangements and also with gas prices that the company believes it can reasonably achieve in the local market. The gas price used in the Kyzyloi and Akkulka Gas Fields report by OPC as of January 1, 2007 ranged from $0.79 per Mcf to $1.02 per Mcf in line with the Gas Sales Contract for the Kyzyloi Field negotiated with a gas buyer in Kazakhstan. Having considered the geological and engineering data in the interpretation process, the Company believes with reasonable certainty that the stated proven reserves represent the estimated quantities of oil and gas to be recoverable in future years under existing operating and economic conditions.

Undeveloped Acreage

The following table summarizes the gross and net undeveloped acreage held under the Ninotsminda, Nazvrevi/Block XIII, Norio/North Kumisi, and Tbilisi production sharing contracts as of December 31, 2006. The information regarding net acreage represents our interest based on our 100% interest in NOC and the subsidiaries holding the Nazvrevi/Block XIII contract, the Norio/North Kumisi and the Tbilisi Block XI^G and XI^H contracts.

PSC	Gross Acres	Gross Square Kilometers	Net Acres	Net Square Kilometers
Ninotsminda, Manavi and West Rustavi covering Block XI^{E}	27,923	113	27,923	113
Nazvrevi and Block XIII	388,447	1,572	388,447	1,572
Norio (Block XI^{C}) and North Kumisi (1)	265,122	1,061	265,122	1,061
Block XI^{G} and XI^{H}	119,845	485	119,845	485
Total	801,337	3,231	801,337	3,231

The following table summarizes the gross and net undeveloped acreage held under the Ninotsminda, Nazvrevi/Block XIII, Norio/North Kumisi and Tbilisi production sharing contracts as of March 13, 2007. The information regarding net acreage represents our interest based on our 100% interest in NOC and the subsidiaries holding the Nazvrevi/Block XIII contract, the Norio/North Kumisi, and the Tbilisi Block XI^{G} and XI^{H} contracts.

PSC	Gross Acres	Gross Square Kilometers	Net Acres	Net Square Kilometers
Ninotsminda, Manavi and West Rustavi covering Block XI^{E}	27,923	113	27,923	113
Nazvrevi and Block XIII	388,447	1,572	388,447	1,572
Norio (Block XI^{C}) and North Kumisi (1)	265,122	1,061	265,122	1,061
Block XI^{G} and XI^{H}	119,845	485	119,845	485
Total	801,337	3,231	801,337	3,231

The following table summarizes the gross and net undeveloped acreage held under the Kazakhstan licenses as of December 31, 2006. The information regarding net acreage represents our interest based on our 70% interest in BN Munai LLP and the subsidiaries holding the licenses through our wholly owned subsidiary TPL.

The following table summarizes the gross and net undeveloped acreage held under the Kazakhstan licenses as of December 31, 2006. The information regarding net acreage represents our interest based on our 70% interest in BN Munai LLP and the subsidiaries holding the licenses through our wholly owned subsidiary TPL.

License	Gross Acres	Gross Square Kilometers	Net Acres	Net Square Kilometers
Kyzyloi	70,918	287	49,643	201
Akkulka	411,916	1,667	288,341	1,167
Greater Akkulka	2,774,993	11,230	1,942,453	7,861
Total*	3,186,849	12,897	2,230,794	9,028

* combined Akkulka & Greater Akkulka Areas

Although the Kyzyloi is potentially a productive field, production has not yet commenced and has been classified as Undeveloped Acreage. A 33 mile (53 Km) pipeline is planned to tie the field to the main Bukhara-Urals gas trunkline. A long-term gas offtake agreement has already been concluded with a planned initial plateau rate of 17.7 MMcf (500,000 MCM) per day.

Office Space

We lease office space in London, England; Guernsey, Channel Islands; Tbilisi, Georgia; and Almaty, Aktobe, Astana and Bozoi in Kazakhstan. The leases have remaining terms varying from six months to eight years and nine months and annual rental charges ranging from approximately $5,000 to $335,000.

Processing, Sales and Customers   Georgia

Georgian Oil built a considerable amount of infrastructure in and adjacent to the Samgori and Ninotsminda

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Fields prior to entering into the production sharing contracts for these Fields. NOC now uses that infrastructure, including initial processing equipment and CSL used it during the term of the Samgori PSC.

The mixed oil, gas and water fluid produced from the Ninotsminda Field wells flows into a two-phase separator located at the Ninotsminda Field, where gas associated with the oil is separated. The oil and water mixture is then transported approximately seven miles (11 Km) either in a pipeline or by truck to Georgian Oil s central processing facility at Sartichala for further treatment.

At Sartichala, the water is separated from the oil. NOC then sells its share of oil in this state to buyers at Sartichala for local consumption or transfer it by pipeline approximately 12 miles (20 Km) to a railhead at Gatchiani or by road tanker to Vaziani rail loading terminal primarily for export sales. At the railheads, the oil is loaded into railcars for transport to the Black Sea port of Batumi, Georgia, where oil can be loaded onto tankers for international shipment. Buyers transport the oil at their own risk and cost from the delivery point at Sartichala.

In 2007 NOC sold all of its oil production to international buyers. In early 2006, NOC sold its oil production in accordance with the terms of a sales agreement concluded with Primrose Financial Group (PFG) in February 2005 which included the sale of oil to other customers nominated by PFG under this agreement. Later oil was sold to third party buyers under unrelated contracts. During the year, oil was purchased and paid for by a total of 2 customers. Of these customers, the following customer represented sales greater than 10% of oil revenue:

Customer	Percent of Oil Revenue
Interchem Energy	91.6%

Management believes that the loss of any customer should not materially adversely affect our production revenues because of the existence of a ready market for our production and an established export route for crude oil from the Caspian area via Georgia and its Black Sea ports. However, there can be no assurance that such substitute purchasers of our production will offer to purchase our production on the same terms and conditions as previously obtained.

In 2005, NOC sold its oil production to four customers of which the following two customers represented sales greater than 10% of oil revenue:

Customer	Percent of Oil Revenue
Interchem Energy	74.5%
Gero	15.8%

In 2004, NOC sold its oil production to 14 customers of which the following four customers represented sales greater than 10% of oil revenue:

Customer	Percent of Oil Revenue
Crownhill	27,5%
Gero	21.9%
Interchem Energy	20.7%
Viva	11.6%

For NOC, sales during 2006 were based on the average of a number of quotations for Dated Brent Mediterranean as quoted in *Platts Crude Oil Marketwire* © with an appropriate average discount for transportation and other charges amounting to $8.44 per barrel. Sales in 2005 were also sold against a Brent quotation at an average discount of $7.50 per barrel. Of the sales in 2004, 43.2 % was sold against a Brent quotation at an average discount of $7.50 per barrel and 56.8 % against an Urals quotation at an average discount of $7.00 per barrel.

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The average sales price and the average production cost per unit (excluding depreciation, depletion and amortization) of oil and gas produced by NOC for each of the last three years was as follows:

Year Ended December 31,	Average Sales Price Oil $/boe	Gas $/Mcf	Unit Production Cost $/boe
2006	53.69	0.66*	10.94
2005	44.78	0.53	14.83
2004	24.94	1.41	5.81

* In 2006, due to the uncollectibility of gas revenues, the Company decided to record gas revenues on a cash basis. Average sales prices above reflect contractual prices for gas delivered and revenues from these deliveries may not have been collected during the year.

Prior to withdrawing from the Samgori PSC in February 2006, CSL sold its share of production to 1 customer for the period to December 31, 2006:

Customer	Percent of Oil Revenue
Interchem Energy	100.0%

In 2005, CSL sold its share of production to four customers of which the following one customer represented sales greater than 10% of oil revenue for the period to December 31, 2005:

Customer	Percent of Oil Revenue
Interchem Energy	80.0%

Since April 2004, when CSL acquired an interest in the Samgori PSC, to December 31, 2004 the Company sold its share of production to seven customers of which the following four customers represented sales greater than 10% of oil revenue for the period:

Customer

	Percent of Oil Revenue
Mercury	34.6%
Interchem Energy	24.0%
GanOil	15.5%
Valimpex	10.9%

For the period in which CSL was selling production in 2006, sales to international markets were based on the average of a number of quotations for Dated Brent Mediterranean with an appropriate discount for transportation and other charges. The average discount to the price of Brent crude oil as quoted in *Platts Crude Oil Marketwire* © for Brent Dated Mediterranean for all sales in 2006 was $8.44 per barrel. Sales in 2005 were also sold against a Brent quotation at an average discount of $6.16 per barrel. The higher discounts during 2005 and 2006 are due to generally smaller quantities of oil being available for sale.

The average sales price and the average production cost per unit of oil and gas produced by CSL for the past three years were as follows:

Year Ended December 31,	Average Sales Price Oil $/boe	Gas $/Mcf	Unit Production Cost $/boe
2006*	59.57	0.00	64.62
2005	46.12	0.00	18.79
2004	33.96	0.00	9.59

* Our interest in the Samgori PSC was terminated with effect from February 16, 2006.

Prices for oil and natural gas are subject to wide fluctuations in response to a number of factors including:

- global and regional changes in the supply and demand for oil and natural gas;
- actions of the Organization of Petroleum Exporting Countries;
- weather conditions;
- domestic and foreign governmental regulations;
- the price and availability of alternative fuels;
- political conditions in the Middle East and elsewhere; and
- overall global and regional economic conditions.

Other Georgian Production Sharing Contracts

Nazvrevi and Block XIII Production Sharing Contract (Nazvrevi PSC)

In February 1998, our wholly owned subsidiary, CanArgo (Nazvrevi) Limited (CNZ) entered into a second production sharing contract with Georgian Oil and the State of Georgia. This contract covers the Nazvrevi (Block XI[D]) and Block XIII areas of East Georgia, an approximately 496,186 acre (2,008 Km^2) exploration area adjacent to the Ninotsminda and West Rustavi Fields and containing existing infrastructure. The agreement came into effect on February 20, 1998 and extends for twenty-five years with the final year of the contract being 2023. We are required to relinquish at least half of the area then covered by the Nazvrevi PSC, but not any portions being actively developed, at five-year intervals commencing in 2003. The first relinquishment was made in 2003, of the southern part of the area, reducing the area to approximately 388,447 acres (1,572 Km^2).

Under the Nazvrevi PSC, CNZ pays all operating and capital costs. We first recover our cumulative operating costs from production. After deducting production attributable to operating costs, 50% of the remaining production (cost recovery petroleum), considered on an annual basis, is applied to reimburse us for our cumulative capital costs. While cumulative capital costs remain unrecovered, the other 50% of remaining production (profit petroleum) is allocated on a 50/50 basis between Georgian Oil and CNZ. After all cumulative capital costs have been recovered by us, remaining production after deduction of operating costs is allocated on a 70/30 basis between Georgian Oil and CNZ, respectively. Thus, while we are responsible for all of the costs associated with the Nazvrevi PSC we are only entitled to receive 30% of production after cost recovery. The allocation of a share of production to Georgian Oil, however, relieves us of all obligations we would otherwise have to pay the State of Georgia for taxes and similar levies related to activities covered by the production sharing contract. Both Georgian Oil and CNZ will take their respective shares of oil production under the Nazvrevi PSC in kind but the intent is to jointly market any available gas production.

The first phase of the preliminary work program under the Nazvrevi PSC involved primarily a seismic survey of a portion of the exploration area and the processing and interpretation of the data collected. The seismic survey has been completed, and the results of those studies have been interpreted and possible oil and gas prospects and exploration drilling locations are being identified. The cost of the seismic program was approximately $1.5 million, and met the minimum obligatory work commitment under the contract. The Department for Protection of Mineral Resources and Mining has confirmed that CNZ have met the requirements of the work program defined in the production sharing contract. The Manavi oil discovery may extend into the Nazvrevi PSC area and the West Rustavi 16 gas discovery located within the Ninotsminda PSC area may extend into Block XIII (the Kumisi prospect), and there are several identified prospects, however as the Nazvrevi and Block XIII area is an exploration area and no discoveries have been made to date, it is not possible to estimate the expenditures needed to discover and, if discovered, produce commercial quantities of oil and gas.

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The number 16 well drilled in Soviet times on the West Rustavi Field was completed in the Cretaceous/Paleocene sequence and was tested and produced at over 1 MMcf (30 MCM) of gas and 3,500 barrels of water per day, and is interpreted to have tested the down dip extent of a Cretaceous gas deposit named Kumisi. Seismic interpretation and mapping has identified the presence of a potentially large prospect, with the crestal part being in the Nazvrevi / Block XIII PSC area. The prospect is potentially of very significant size with the principal risk being closure on the structure. A drilling location for the Kumisi #1 well has been identified within the Nazvrevi PSC. This prospect is located approximately 7.5 miles (12 Km) southeast of Tbilisi and is close to the domestic gas transportation grid (nearest pipeline approximately 2.2 miles (3.5 Km) (500mm, 10-12 Atm pressure) and a pipeline at 10 miles (16 Km) (700mm, 9-10 Atm), the route of the new South Caucasus gas trunkline from Azerbaijan to Turkey, and is approximately 12.5 miles (20 Km) west of the Gardabani thermal power plant and Rustavi industrial complex.

On March 3, 2006 we announced that CNZ had signed a Memorandum of Understanding (MOU) with the Georgian Government which includes the terms of a take-or-pay natural gas supply contract relating to gas sales from the Kumisi gas prospect within the Nazvrevi / Block XIII PSC area. The gas supply contract will be with the Georgian State, secured against appropriate bank guarantees, in which CNZ will supply gas from Kumisi based on a pricing formula under which gas is initially supplied at a contract price of $1.56 per Mcf ($55 per MCM), increasing to $2.28 per Mcf ($80 per MCM) by the tenth contract year, after which escalation will be based on European Union heavy fuel oil price changes. The contract will be for the entire field life. However, after the tenth year, CNZ has the option of selling to third parties if the price obtained is 10% above the contract price at that time.

This MOU became effective in February 2007 on receipt of regulatory approval and a drilling permit and CNZ commenced drilling the Kumisi #1 well on February 7, 2006. The well which is being drilled with CanArgo Rig #2 is expected to reach total depth of 12,140 feet (3,700 meters) in the Cretaceous by late June. Surface casing has been set at a depth of 1,004 feet (306 meters) and the well is currently drilling ahead at approximately 4,921 feet (1,500 meters) in the Middle Eocene.

Norio (Block XI^{C}) and North Kumisi Production Sharing Agreement (Norio PSA)

In December 2000, CanArgo, through its then 50% owned subsidiary CanArgo Norio Limited (CNL), entered into a third production sharing contract with the State of Georgia represented by Georgian Oil and the State Agency for Regulation of Oil and Gas Resources in Georgia. The Norio PSA covers the Norio and North Kumisi blocks of East Georgia, an exploration area of approximately 265,122 acres (1,061 Km ^{2}), following the first contractual relinquishment in April 2006, adjacent to the Ninotsminda and Samgori Fields. The Norio PSA came into effect on April 9, 2001 and extends for a period of twenty-five years with the final year of the contract being 2026. We are required to relinquish at least 50% of the remaining contract area, but not any portions being actively developed at five-year intervals commencing in 2011 up to 2026. There are two existing oil fields on the Norio PSA area, Norio and Satskhenisi which are old, small, relatively shallow fields and which produce small quantities of oil. CNL has determined production from these fields to be uneconomic, and the fields are currently being operated by Georgian Oil whereby Georgian Oil takes all production to compensate it for its costs under what is effectively a social program. If CNL wishes, it could take over field operations and production from these fields forthwith.

The commercial terms of the Norio PSA are similar to those of the Nazvrevi PSC with the exception that after all cumulative capital costs have been recovered by CNL, remaining production after deduction of operating costs is allocated on a 60/40 basis between Georgian Oil and CNL, respectively. Thus, while CNL is responsible for all of the costs associated with development of the Norio PSA, it is only entitled to receive 40% of production after cost recovery. On September 30, 2004 we announced that we had increased our interest in CNL, by buying out the remaining minority shareholders who held a 25% interest in that company. CNL is now a wholly owned subsidiary of CanArgo.

The first phase of the preliminary work program under the Norio PSA involved primarily a seismic survey of a portion of the exploration area and the processing and interpretation of the data collected. The seismic survey has been completed, and the results of those studies have and will continue to be interpreted. In addition to the main target, which is the Middle Eocene, the potential of the license area to produce from the Miocene, Sarmatian, Upper Eocene and Cretaceous is being assessed. The cost of the seismic program was approximately $1.5 million.

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The second phase of the preliminary work program under the Norio PSA commenced in January 2002 when the first exploration well named MK72 was spudded on the Norio prospect using the CanArgo Ural Mash rig. Norio is a large prospect identified at Middle Eocene level and is analogous in size to the nearby Samgori and Ninotsminda Field complex immediately to the south and east of the block. It has been reported that the Samgori Oil Field alone has produced approximately 180 million barrels of oil to date.

Completion of the MK72 well was delayed as a result of technical problems encountered whilst drilling, and the need to farm out a portion of the equity in the block in order to partly fund the drilling. In September 2003, CNL signed a farm-in agreement relating to the Norio PSA with a wholly owned subsidiary of Georgian Oil, the Georgian State Oil Company. This farm-in agreement obligated Georgian Oil to pay up to $2.0 million to deepen, to a planned depth of 16,733 feet (5,100 meters) the MK-72 well in return for a 15% interest in the contractor share of the Norio PSA. Georgian Oil also had an option, exercisable for a limited period after completion of the well, to increase its interest to 50% of the contractor share of the Norio PSA on payment to CNL of $6.5 million. Due to Georgian Oil s inability to continue to fund the drilling of the well, operations were subsequently suspended and only resumed after May 2005 when we repaid to Georgian Oil the investment it had made in the MK72 well to terminate the farm-in agreement and option and secure a 100% working interest in the Norio PSA.

In August 2005 the Saipem drilling rig and Baker oil-based mud system was mobilized to the MK72 exploration well as our Ural Mash rig had difficulty drilling through a highly over-pressured section of swelling clays above the prognosed target zone. On December 29, 2005 we announced that the MK72 well reached a depth of 16,076 feet (4,900 meters) in the Middle Eocene reservoir having encountered very good oil and gas shows. Before the well could be drilled to the planned depth and tested, the bottom hole assembly (BHA) became stuck due to hole collapse. Subsequent attempts to retrieve the BHA were not successful and we decided to abandon the lower target due to a limited chance of sidetracking the well at this depth in a small diameter hole and to focus our attention on the shallower oil discovery in the overlying Oligocene sands which were the secondary target for the well. From the data obtained from the Middle Eocene (the primary target for the well) we believe that an oil discovery has been made at this level, and that the reservoir has exhibited both permeability (evidenced by drilling mud losses whilst drilling) and the presence of movable light oil. As such, even though the Middle Eocene has not been fully evaluated, the MK72 well has encountered the Middle Eocene reservoir on prognosis, and with hydrocarbons thus achieving many of the objectives of this wildcat exploration well.

A comprehensive testing program on the oil bearing Oligocene sandstones encountered in the Norio MK72 well commenced in mid-March 2006 when a total of 322 feet (98 meters) of net sands were perforated over the interval 12,096 feet (3,687 meters) to 13,622 feet (4,152 meters). These sands had good oil shows whilst drilling, with oil to surface and with hydrocarbons being interpreted on the electric logs which also indicated a substantial thickness of net pay sands. Following an extensive testing program, the well sustained flow on a small choke size with low average gross fluid rates of approximately 13 barrels per day consisting of light 48.6ºAPI oil, gas and water.

A number of surge clean up flows, a re-perforation of selected intervals, and a low pressure hydrofrac using our own pumping unit have been attempted but these have not improved reservoir deliverability. It is believed that the current flow is limited to a thinner, less permeable, interval whilst the better quality reservoir remains isolated due to potential reservoir damage caused by the invasive fluid damage of the drilling mud. The lower zones in the well, which would have been in communication with the Oligocene interval through the well-bore, were drilled with a 1.9 to 2.2 Specific Gravity (SG) mud due to anticipated reservoir pressures while the results from the testing program indicate that the mid interval reservoir pressure for the Oligocene whilst still over pressured, is lower at 1.7 SG equivalent. As a result of possible mud damage, the current perforations may have not penetrated deep enough beyond the damaged zone to allow proper communication between the more permeable formations and the well-bore.

We considered mobilising a more powerful fraccing unit and equipment to Georgia in order to pump a propant and fluid into the well at high pressure and volume, but the potential for this technology is limited due to a lack of a cement bond behind the casing and the large interval which has been perforated. The well has been left on test production for the past several months but there has been no discernable increase in gross fluid production rate. As we would appear to have exhausted all the low cost options available to us at this time to bypass any damage that may exist in the near-well-bore area and establish better communication between the well-bore and the reservoir, we believe that the only effective option remaining is to sidetrack the well or to drill a new well. The latter, of course, would enable us to attempt to test both the Oligocene and Middle Eocene intervals both of which are considered to have significantly reduced geological risk as a result of drilling this well.

The Norio PSA covers a large exploration area with what management believe to be good oil and gas potential with the presence of reservoir rocks and moveable hydrocarbons having been confirmed by drilling. We have mapped several significant prospects at different stratigraphic levels within the area several of which are on trend with the MK72 well. Both the Oligocene and Middle Eocene prospects as mapped are potentially large and warrant appraising. It is planned, subject to financing being available from internal resources or through a farm out arrangement, that an appraisal well will be drilled to fully evaluate these attractive discoveries, with the well being designed to enter the Middle Eocene reservoir with a larger hole size.

As the area in which we are currently drilling is an exploration area with no commercial discoveries (excluding the small shallow fields currently operated by Georgian Oil), it is not possible to estimate the expenditures needed to discover and, if discovered, produce commercial quantities of oil and gas.

Block XI^G and XI^H Production Sharing Contract (Tbilisi PSC)

In November 2002, our subsidiary, CanArgo Norio Limited (CNL), won the tender for the oil and gas exploration and production rights to the Tbilisi PSC, an area of approximately 119,845 acres (485 Km^2) in eastern Georgia adjacent to the Norio, Block XIII and West Rustavi areas. In July 2003, it was announced that CNL, had signed a Production Sharing Contract covering these areas. The Tbilisi PSC came into effect on September 29, 2003 and will continue for an initial period of ten years at which time it will terminate unless we have made a commercial discovery in which case the PSC will continue in full force and effect until September 29, 2028. The commercial terms of the Tbilisi PSC are similar to those of the Norio PSA with the exception that Georgian Oil does not have an option to acquire an interest in the contractor party s share following a commercial discovery.

Under the Tbilisi PSC we have a commitment to evaluate existing seismic and geological data which we have completed and acquired additional seismic data within three years of the effective date of the contract which is September 29, 2003. The State Agency for Oil & Gas Regulation in Georgia verbally consented to an extension to the period within which the data should be acquired to the end of 2007, but due to an internal reorganisation of the State Agency, we are only now working with the State Agency to amend the Tbilisi PSC accordingly. The total commitment over the remaining period is $350,000.

Following our acquisition of the minority shareholding in CNL in September 2004, our interest in the Tbilisi PSC increased from 75% to 100%.

The Kumisi Cretaceous gas prospect which is being tested by the Kumisi #1 well extends into the southern part of Block XI^G. The well is located within the Nazvrevi / Block XIII PSC area just to the south of the block boundary with the Tbilisi PSC.

Exploration, Appraisal and Development Activities Kazakhstan

In December 2003, we announced details of the conditional acquisition of certain oil and gas interests in Kazakhstan which had previously been owned by the UK public company, Atlantic Caspian Resources plc (ACR). This was to be achieved through a newly established company, Tethys Petroleum Investments Limited (now renamed Tethys Petroleum Limited (TPL)) on certain conditions being satisfied. These interests were represented as including a 70% interest in BN Munai LLP (BNM), a Kazakh limited liability partnership, which was represented as holding certain exploration and production interests in Kazakhstan including the Akkulka exploration licence and contract and Kyzyloi production licence. Immediately prior to the agreement between TPL and ACR, and as part of that transaction, we entered into an agreement allocating a 45% interest in TPL to Provincial Securities Limited (an investment company to which Mr. Russell Hammond, one of our non-executive directors, is an Investment Advisor) in consideration for future services of providing advice, help and assistance concerning funding the development of TPL. This transaction resulted in us holding a 45% non-controlling interest in TPL with the remaining interest holder in TPL being ACR with a 10% interest. At this time the licence position with regard to the Akkulka exploration area was subject to review by the Kazakh authorities and further negotiation was required to secure this. In addition the Kyzyloi production contract had not been signed and certain clarification was required with regard to registration of BNM.

TPL and BNM subsequently negotiated a two year extension on the Akkulka Exploration Contract, and a further two year extension was negotiated last year. On June 8, 2004, we announced that that deal was finalized with the registration with the Kazakh authorities of TPL s interest in BNM, and the Kyzyloi Production Contract was signed in May 2005.

On June 7, 2005, we announced that we had acquired the remaining 55% of TPL by way of a share exchange with the other owners of TPL and TPL had accordingly become a wholly owned subsidiary of the CanArgo Group.

On March 3, 2006, we announced the finalisation of a $13 million private placement of Senior Subordinated Convertible Guaranteed Notes due September 1, 2009 the net proceeds of which are to be used to fund the development of TPL s assets in Kazakhstan. The noteholders have the right (as an alternative to conversion into CanArgo common stock) for a period of one year from closing (or, if later, until the consent of CanArgo s Senior Noteholders is obtained), to convert their notes into up to a 25% equity interest in CanArgo s share of TPL (based on a $52 million valuation for CanArgo s share of TPL and adjusted appropriately upwards for a lower valuation).

BNM s interest centers on the Akkulka area, a 411,916 acre (1,667 Km^2) exploration area and the shallow Kyzyloi Gas Field, both located in the North Ustyurt basin in southern Kazakhstan some 41 miles (65 Kms) to the north of the border with the Karalkalpak region of Uzbekistan and 34 miles (55 Kms) to the north-west of the Aral Sea. In the four years prior to our ownership interest, BNM had drilled two deep exploration wells in the Akkulka area, which they plugged and abandoned with minor hydrocarbon shows. The original term of the Exploration Contract was until 17 September 2003, but an extension until September 2005 was agreed, and at that time a further extension until 17 September 2007 was agreed by the Expert Commission, subject to modification to the Contract.

On the Kyzyloi Gas Field a development program is underway. The Kyzyloi Field Contract covers a 70,918 acre (287 Km^2) area. The original licence was issued in June 1997 to Kazakgas, as state entity, and acquired by BNM in 2001 with an initial term until June 2007. In January 2005 the Ministry of Energy and Mineral Resources agreed to extend the period of production on Kyzyloi to June 2014, subject to modification to the Contract, and the Production Contract itself was signed and registered on May 6, 2005.

The field contains sweet natural gas (97% methane) reservoired in shallow sandstones at a depth of approximately 1,640 feet (500 meters) which was discovered, but not developed, during the 1960 s. This field is located close to the Bukhara-Urals gas trunkline, and to the south of the Bozoi gas storage facility. BNM has carried out an extensive workover and testing program on the Kyzyloi Field wells, and the six wells tested to date for the initial development have flowed at a cumulative rate of over 24 million cubic feet (688,000 cubic meters) of gas per day. A gathering system, 32 mile (51 Km) pipeline and compressor station is in the process of construction to connect the Kyzyloi development to the Bukhara-Urals gas trunkline, with the initial planned production rate being 22 million cubic feet (625,000 cubic meters) per day and with first gas planned for late spring 2007. BNM believes that there is significant additional potential both in the Kyzyloi Field and in its surrounding Akkulka exploration contract area. As such the pipeline and associated facilities are being designed such that they could be upgraded to throughput up to 78 million cubic feet (2.2 million cubic meters) per day of gas production.

In January 9, 2005 we announced that BNM had executed a natural gas supply contract with Gaz Impex S.A. LLP (Gaz Impex) relating to gas sales from the Kyzyloi Gas Field. The contract, which has a term until June 2014, is based on a take-or-pay principle and covers all gas produced from the Kyzyloi Field Production Contract area. Gas will be supplied to Gaz Impex at a tie in point to the

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Bukhara-Urals gas trunkline via the pipeline to be constructed between the field and the trunkline. The price of gas to be supplied at the tie in point averages $1.13 per Mcf ($32 per MCM) over the life of the contract, with Gaz Impex providing bank guarantees against payment. We believe that this is one of the first take-or-pay contracts signed in Kazakhstan for a dedicated dry gas development. Gaz Impex is one of the leading gas marketing companies in Kazakhstan, and is currently involved with gas purchase and supply contracts both within Kazakhstan and in surrounding countries. Previously in October 2005, we announced the execution of a Memorandum of Understanding covering co-operation in the gas sector in Kazakhstan with Gaz Impex.

In 2005 / early 2006 BNM undertook a five well exploration program targeting shallow gas anomalies which may be similar to the Kyzyloi Field within the Akkulka Exploration Contract Area. All five of these wells had gas indications on wireline logs and to date two have been fully production tested, namely AKK04 and AKK05. The AKK05 well, located 4 miles (6.5 Km) north east of the Kyzyloi Field, flowed gas at a rate of 7.9 MMcf (223 MCM) per day. This well effectively extended the Kyzyloi Field to the north east, including an untested fault block (NE Kyzyloi), and work is currently underway with respect to extending the area of the Kyzyloi Production Contract to include the AKK05 well which will be included as a production well in the Kyzyloi Field development. The AKK04 exploration well, located some 12.5 miles (20 Km) east of the Kyzyloi Field, flowed gas at a stabilized flow rate of 8.8 MMcf (250 MCM) of gas per day, and this well, now named Central Akkulka, has been declared a commercial discovery by BNM. An appraisal / exploration well (AKK06) was drilled by BNM late in 2006 to appraise and extend the Central Akkulka accumulation to the south west. This well had gas indications on the wireline logs but remains to be tested as part of an integrated testing program currently underway. It is planned to tie the AKK04 discovery into the Kyzyloi development, initially by way of a long term extended well test, but then by the application for a separate production contract, once the Central Akkulka accumulation has been fully evaluated.

In the other three exploration wells which have been drilled to date, AKK01, AKK02 and AKK03, gas indications were observed during drilling and in thin sands on wireline logs. These sands are present at several stratigraphic levels within the wells. AKK01 lies to the north east of the Kyzyloi Field on a prospect named North Akkulka. Testing of the AKK01 well is planned for Q2 2007 as part of the current integrated testing program. The AKK02 and AKK03 wells lie to the south east of the Kyzyloi Field on a prospect named South Akkulka. AKK03 is updip of AKK02 and encountered a gas bubble whilst drilling and with gas being noted on the wellhead. This well is currently in the process of being fully flow tested. The downdip well AKK02, which has thin sandstones showing possible gas on wireline logs but with relatively high water saturations, was tested and flowed water from these sands, this well therefore delineating the downdip extent of the South Akkulka prospect at this level (although higher untested sands do exist) which remains to be tested for commercial flow by the AKK03 well.

Further exploration continues on the Akkulka block with four more wells planned for 2007. Currently the AKK07 (South West Akkulka) well is drilling and is currently at a depth of 902 feet (275 meters).

Initial work is now completed on a geophysical remapping of the Akkulka exploration block. This work has confirmed the presence of additional potential shallow gas prospects (some of which are being drilled in the current drilling program), and also some potentially large prospects at Jurassic/Triassic levels. Regional geological studies suggest that these deeper prospects could have potential for gas condensate or oil deposits.

In November 2005 we announced that BNM had completed the acquisition of a 100% interest in the Greater Akkulka Exploration & Production Contract. This contract, which is for a period of 25 years from 2005, with an initial six year exploration period, covers an area of approximately 2.78 million acres (11,230 Km^2) surrounding the Akkulka area. BNM considers that this area has substantial exploration potential, with extensions of the shallow gas exploration targets and deeper Mesozoic plays. This large area within a proven hydrocarbon system, has potential towards the south and east (towards the Aral Sea), where the Paleogene sand sequence is thought to become thicker and of better quality, and towards the west and north where potential may exist for stratigraphic and pinch-out plays. Initial seismic mapping has shown the presence of several shallow gas prospects and it is planned that drilling would commence on these structures in early 2008. Meanwhile additional 2D seismic data is being acquired this year on the Greater Akkulka Contract Area as part of the work commitment under the contract and to infill the western part of the area prior to the contractual relinquishment of 20% of the area at the end of 2007.

A seismic contractor has been selected and work is expected to commence in the summer of 2007.

In June 2006, we announced that we were planning a spin-out of TPL, and that TPL was planning to seek admission to the AIM market of the London Stock Exchange and raise funds for its development and exploration activities in Kazakhstan. It was planned that we would retain a significant, but not controlling, equity interest in TPL after the admission of TPL to the AIM market. The intention of this spin-out was is to enable the Kazakh assets to be financed whilst minimising dilution of the Georgian assets and potentially raising additional funds for the Georgian operations. In August 2006, we announced certain appointments of new independent directors to the TPL Board in preparation for the spin-out and in September 2006, we announced that TPL had completed a $5 million interim financing in advance of the planned spin-out. In view of market conditions, our brokers were unable to indicate that sufficient capital would be raised to fulfil the capital required to proceed with the AIM admission as planned.

The financing was in the form of the issue of $5 million TPL senior secured notes redeemable on August 31, 2008. TPL has the ability to prepay these notes and the notes are to be automatically prepaid in the event of a flotation or listing of TPL. The proceeds of this financing were to be used to finance through BNM the development of the Kyzyloi Field. The loan note holders also received warrants to acquire ordinary shares in the capital of TPL or, at the discretion of TPL, a royalty in respect of production. The number of shares into which the warrants convert is dependent on the timing of the proposed flotation and the flotation price.

In February 2007, we announced that TPL had completed a private placement with a limited group of private investors raising gross proceeds of approximately $17.35 million, by issuing in total approximately 34.7 million new ordinary shares in TPL (representing approximately 33% of the issued and outstanding share capital of TPL) and with CanArgo Limited (a wholly owned subsidiary of CanArgo) retaining our 70,000,000 shares in TPL representing the remaining 67%. Under the terms of the Shareholders Agreement entered into with the new private investors, TPL is subject to certain positive and negative covenants which require the consent of the holders of not less than 75% of the ordinary shares in issue in TPL from time to time (the Shareholder Majority). The Agreement also outlines certain provisions in relation to the conduct of the TPL business and provided that the intention of TPL, CanArgo Limited and the Investors, as defined in the Agreement, is to use their reasonable endeavours to work towards a listing of TPL as soon as practicable, subject to (i) the financial and commercial circumstances of TPL, and the pre-money valuation of TPL prior to the listing being acceptable to the Shareholder Majority; and (ii) the terms and amounts (if any) raised by TPL on such listing being acceptable to the board of TPL. Tethys has now entered into an Engagement Letter with Jennings Capital Inc. of Calgary, Alberta (JCI) engaging JCI to act as lead agent with respect to a planned initial public offering (IPO) and listing of Tethys on the Toronto Stock Exchange (TSX) later this year. In addition McDaniel and Associates Consultants Limited have been engaged to carry out an independent evaluation of Tethys projects in connection with the proposed listing. The full details of the planned IPO have yet to be finalised.

Agreement has now also been reached whereby, subject to any required Kazakh regulatory approvals Tethys, through its wholly owned subsidiary Tethys Kazakhstan Limited (TKL) will acquire the 30% of BNM it does not own in return for 30 million shares in Tethys, and making BNM a wholly owned subsidiary of TKL. TKL s interest in BNM is currently the principal asset of Tethys. Following this share swap there will be approximately 134.7 million shares in Tethys of which CanArgo will own 70 million (52 %).

In February 2007, we also announced that TPL has signed a Protocol of Intent (the Protocol) with the Ministry of Energy of the Republic of Tajikistan and the State Committee for Investments and Property Management of the Republic of Tajikistan giving TPL the exclusive right to carry out technical evaluations and negotiations with the aim of entering into a contractual arrangement: to carry out oil and gas exploration activities in the Kulibsky region of Southern Tajikistan; to consider involvement in the Alimtai prospect in that region; and to consider co-operation in increasing production on currently operating fields in Tajikistan. A phase of data collection, interpretation and negotiation is planned over the next six months, with the aim of concluding basic agreements during this period.

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Refining and Other Activities

We also have engaged in other oil and gas activities in Georgia and elsewhere. A discussion of discontinued operations is incorporated herein by reference from note 20 to the consolidated financial statements included elsewhere herein.

Drilling Rigs and Associated Equipment

We own several items of drilling equipment, and other related machinery primarily for use in our Georgian operations. These include three drilling rigs, pumping equipment and ancillary machinery. This equipment is currently being used by our operator company to drill exploration wells and provide support to our development work on the Ninotsminda Field and on the Manavi and Norio discoveries.

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Employees

As of December 31, 2006, we had 187 full time employees. Of our full time employees, the entity acting as operator of the Ninotsminda Field for NOC has 124 full time employees, and substantially all of that company s activities relate to the production and development of the Ninotsminda Field. In Kazakhstan our subsidiary BN Munai LLP employed 35 full time employees in Almaty, Aktobe, Astana and Bozoi principally involved with work on the Kyzyloi Field development and Akkulka appraisal / development program. We have not experienced any strikes, work stoppages or other labour disputes and management believes the Company s relations with its employees are satisfactory.

ITEM 3. LEGAL PROCEEDINGS.

On September 12, 2005, WEUS Holding Inc (WEUS) a subsidiary of Weatherford International Ltd lodged a formal Request for Arbitration with the London Court of International Arbitration against CanArgo Energy Corporation in respect of unpaid invoices for work performed under the Master Service Contract dated June 1, 2004 between the Company and WEUS for the supply of under-balanced coil tubing drilling equipment and services during the first and second quarter of 2005. Pursuant to the Request for Arbitration, WEUS demand for relief is $4,931,332. The Company is contesting the claim and has filed a counterclaim.

On July 27, 2005, GBOC Ninotsminda, an indirect subsidiary of the Company, received a claim raised by certain of the Ninotsminda villagers (listed on pages 1 to 76 of the claim) in the Tbilisi Regional Court in respect of damage caused by the blowout of the N100 well on the Nintosminda Field in Georgia on September 11, 2004. An additional claim was received in December 2005 and amended in March 2006, thus bringing the relief sought pursuant to both claims to the sum of approximately 314,000,000 GEL (approximately $184,000,000 at the exchange rate of GEL to US dollars in effect on December 31, 2006).

We believe that we have meritorious defenses to both claims and are defending them vigorously.

The Company has been named in with a group of defendants by former interest holders of the Lelyaki oil field in Ukraine. The plaintiffs are seeking damages of approx 600,000 CDN (approx $517,000 at December 31, 2006 exchange rates). The former owners of UK-Ran Oil Company disposed of their investment in the field prior to selling the Company to CanArgo. CanArgo believes the claim against it to be meritless.

Other than the foregoing, as at December 31, 2006 there were no legal proceedings pending involving the Company, which, if adversely decided, would have a material adverse effect on our financial position or our business. From time to time we are subject to various legal proceedings in the ordinary course of our business.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

No matters were submitted to a vote of our security holders during the fourth quarter of the year ended December 31, 2006.

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PART II

ITEM 5. MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

CanArgo is listed on the Oslo Stock Exchange in Norway (OSE) where our stock trades under the symbol CNR and also on the AMEX where our common stock trades under the symbol CNR . Until April 21, 2004 our common stock traded on the NASDAQ Over The Counter Bulletin Board (OTCBB) under the symbol GUSH .

The following table sets forth the high and low sales prices of the common stock on the OSE and the AMEX for the periods indicated. Average daily trading volume on these markets during these periods is also provided. OSE and AMEX data is derived from published financial sources. Sales prices on the OSE were converted from Norwegian kroner into United States dollars on the basis of the daily exchange rate for buying United States dollars with Norwegian kroner announced by the central bank of Norway. Prices in Norwegian kroner are denominated in NOK . For historical price verification in Norway please see http://uk.table.finance.yahoo.com/k?s=cnr.ol&g=d and for exchange rate conversion $/NOK for the corresponding dates please see www.oanda.com/convert/fxhistory.

	OSE			AMEX		
	High	Low	Average Daily Volume	High	Low	Average Daily Volume
Fiscal Quarter Ended						
March 31, 2005	1.98	1.08	2,296,436	1.94	1.06	2,396,215
June 30, 2005	1.47	0.69	3,058,647	1.48	0.66	1,589,495
September 30, 2005	2.18	0.79	5,691,163	2.25	0.69	1,645,733
December 31, 2005	1.85	1.09	3,689,260	1.86	1.15	1,287,433
March 31, 2006	1.44	1.07	1,109,034	1.46	1.03	804,198
June 30, 2006	1.18	0.65	1,260,919	1.20	0.65	691,559
September 30, 2006	1.58	0.63	7,025,224	1.55	0.62	1,278,022
December 31, 2006	1.63	1.04	2,556,167	1.66	1.05	752,662

At March 9, 2007, the closing price of our common stock on $1.01 on both the AMEX and the OSE. On March 9, 2007 one U.S. dollar equalled 6.19 Norwegian kroner.

On March 1, 2007 the number of holders of record of our common stock was approximately 15,000. We have not paid any cash dividends on our common stock.

Dividend Policy

We currently intend to retain future earnings, if any, for use in our business and, therefore, do not anticipate paying any cash dividends in the foreseeable future. The payment of future dividends, if any, will depend, among other things, on our results of operations and financial condition and on such other factors as our Board of Directors may, in their discretion, consider relevant. In addition, the terms of our outstanding notes prohibit us from paying dividends and making other distributions.

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Equity Compensation Plan Information

The following table provides information as of December 31, 2006 with respect to shares of our common stock that may be issued under our equity compensation plans as of December 31, 2006:

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price per share of outstanding options, warrants and rights (b)	Number of securities to remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	9,096,000	$ 0.76	8,923,667
Equity compensation plans not approved by security holder	535,000	0.10	
	9,631,000	$ 0.73	8,923,667

PERFORMANCE GRAPH

The chart set forth below shows the value of an investment of $100 on December 31, 2002 in each of the Company s Common Stock, the American Stock Exchange Index and a peer group of certain oil and gas exploration and development companies. The peer group consists of the following independent oil and gas exploration companies: Aminex plc, Bow Valley Energy Ltd., EuroGas, JKX Oil & Gas plc, Lundin, Ramco Energy plc and Soco International plc. As the Company is listed on the American Stock Exchange, the AMEX Index of listed stocks has been included in the comparison table.

All values assume reinvestment of the pre-tax value of dividends paid by companies included in these indices and are calculated as of December 31 of each year. The share price performance is weighted based on market capitalisation using the number of outstanding shares at the beginning of each period. The historical stock price performance of the Common Stock shown in the performance graph below is not necessarily indicative of future stock price performance.

Year End	2001	2002	2003	2004	2005	2006
CNR	100	21	222	521	1,132	1,528
Peer Index	100	182	398	492	1,099	1,605
AMEX	100	97	138	169	207	242

ITEM 6. SELECTED FINANCIAL DATA.

Reference is hereby made to the Section entitled CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS with respect to certain qualifications regarding the following information.

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The following selected financial data, derived from our historical audited consolidated financial statements, reflect the historical results of operations and selected balance sheet items of CanArgo and should be read in conjunction with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and the consolidated financial statements included in Item 8. Financial Statements and Supplementary Data herein.

	Year Ended December 31,				
Reported in $000 s Except for per Common Share Amounts	**2006**	**2005**	**2004**	**2003**	**2002**
Financial Performance					
Operating revenues from continuing operations	6,527	5,279	7,833	8,105	5,486
Impairment of oil and gas properties and other assets	39,000				
Operating loss from continuing operations	(53,637)	(11,744)	(4,026)	(159)	(4,902)
Other expense	(7,577)	(1,194)	(2,226)	(597)	(576)
Net loss from continuing operations	(61,214)	(12,938)	(6,262)	(756)	(5,478)
Net income (loss) from discontinued operations, net of taxes and minority interest(1)	673		1,504	(6,608)	150
Cumulative effect of change in accounting policy				41	
Net loss	(60,541)	(12,335)	(4,758)	(7,323)	(5,328)
Net loss per common share basic and diluted before cumulative effect of change in accounting principle from continuing operations	(0.27)	(0.06)	(0.05)	(0.01)	(0.06)
Net loss per common share basic and diluted before cumulative effect of change in accounting principle from discontinued operations	(0.27)	(0.06)	(0.01)	(0.07)	(0.00)
Net loss per common share basic and diluted	(0.27)	(0.06)	(0.04)	(0.08)	(0.06)
Cash generated by (used in) operations	(9,320)	(8,872)	(4,312)	4,431	1,635
Working capital	11,628	14,808	23,952	3,890	10,646
Total assets	136,485	147,448	105,160	73,360	70,736
Long term obligations	42,296	26,524	1,254		
Temporary Equity	2,120	2,120			
Stockholders equity	81,489	107,849	96,821	56,708	62,105
Cash dividends per common share					

(1) In September 2002, CanArgo approved a plan to sell CSOP to finance its Georgian and Ukrainian development projects and in October 2002, CanArgo agreed to sell its 50% holding to Westrade Alliance LLC, an unaffiliated

company, for $4 million in an arms-length transaction, with legal ownership being transferred upon receipt of final payment due in August 2003. The agreed consideration to be exchanged does not result in an impairment of the carrying value of assets held for sale. The assets and liabilities of CSOP have been classified as Assets held for sale and Liabilities for sale for all periods presented. The results of operations of CSOP have been classified as discontinued for all periods presented. The minority interest related to CSOP has not been reclassified for any of the periods presented, however net income from discontinued operations is disclosed net of taxes and minority interest.

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

Qualifying Statement With Respect To Forward-Looking Information and Risks

THE FOLLOWING INFORMATION CONTAINS FORWARD-LOOKING INFORMATION. See Cautionary Statement Regarding Forward-Looking Statements above and Forward-Looking Statements below. Our activities and investments in our common stock involve a high degree of risk. Each of the risks in Item 1A Risk Factors may have a significant impact on our future financial condition and results of operations. The following should be read in conjunction with the audited financial statements and the notes thereto included herein.

General

We are an independent energy company engaged in operations located primarily in countries comprising the former Soviet Union involving the acquisition, exploration, development, production and marketing of crude oil and, to a lesser extent, natural gas. Our principal means of growth has been through the acquisition and subsequent development and exploitation of producing oil and gas properties by means of entering into production sharing arrangements and licence arrangements with governmental or local oil companies. As a result of our historical exploration and acquisition activities, we believe that we have a substantial inventory of exploitation and development opportunities, the successful completion of which is critical to the maintenance and growth of our current production levels. We have incurred net losses in the last five years, and there can be no assurance that operating income and net earnings will be achieved in future periods. Our financial results depend upon many factors, particularly the following factors which most significantly affect our results of operations:

- the sales prices of crude oil and, to a lesser extent, natural gas;
- the level of total sales volumes of crude oil and, to a lesser extent, natural gas;
- the availability of, and our ability to raise additional, capital resources and provide liquidity to meet cash flow needs; and
- the level and success of exploration and development activity.

Reserves and Production Volumes

Year end gross total proved oil reserves at the Ninotsminda Field were 3.379MMbbl down 12% from 2005 s 5.499 MMbbl. Over the same period, gross total proved natural gas reserves from the Ninotsminda field on Georgia and the Kyzyloi field in Kazakhstan were 33.147 billion cubic feet down 6% from 2005 s 35.196 billion cubic feet.

Because our proved reserves will decline as crude oil and natural gas and natural gas liquids are produced unless we acquire additional properties containing proved reserves or conduct successful exploration and development activities, our reserves and production will decrease. Our ability to acquire or find additional reserves in the near future will be dependent, in part, upon the amount of available funds for acquisition, exploitation and development projects.

Exploitation and Development Activity

Ninotsminda

Following the rehabilitation and development work undertaken on the Ninotsminda Field, we realised that the performance of wells was being negatively impacted by being drilled over-balanced with conventional drilling methods and we decided to employ under-balanced drilling technology in order to maximise productivity and recoverability from the field. It was planned that future horizontal wells on the field should be drilled using this technology. In June 2004, we signed a contract with WEUS Holding Inc., a subsidiary of Weatherford International Ltd (Weatherford), for the supply of Under-Balanced Coiled Tubing Drilling (UBCTD) services to our projects in Georgia. Under the terms of the contract, Weatherford were to supply and operate a UBCTD unit to be used on a program of up to 14 horizontal well-bores on our Ninotsminda and Samgori Fields (we were party to the Samgori PSC at this time). Elsewhere in the oil industry, the use of under-balanced drilling techniques has been shown to result in significantly less formation damage, resulting in higher sustained production rates and ultimate recovery. At the same time, utilisation of coiled tubing drilling gives greater flexibility in the drilling process and in the control of the horizontal section. It was considered that these combined drilling technologies would provide the best way to develop and produce both the Ninotsminda and Samgori Fields.

We planned to drill at least five under-balanced horizontal sidetracks on the Ninotsminda Field and UBCTD operations started on the first well in the program, the N22H well, in December 2004, but due to technical problems with the equipment the under-balanced drilling was not completed until late February 2005 and then only with a much shorter than planned section being drilled, and the well not achieving its objective, despite flowing gas at reported high rates through the gas cap section. Subsequent operations by Weatherford on both

N100H2 and N49H wells also proved unsuccessful, with Weatherford failing to drill any horizontal section in these wells. Progress was hampered by multiple failures of the downhole motors, other equipment malfunctions and the loss of bottom hole assemblies in the wells.

Following the failure of Weatherford to successfully complete any horizontal sidetrack development wells on the Ninotsminda Field using UBCTD technology, Weatherford demobilized its equipment and left Georgia in July 2005. Despite this lack of success, which we attribute mainly to multiple equipment failures, we still believe that under-balanced technology is an appropriate technology for the development of this type of reservoir. However, as we withdrew from the Samgori PSC in February 2006, it would be prohibitively expensive to mobilise an UBCTD unit to Georgia solely for a drilling campaign on the Ninotsminda Field and we are considering other ways in which to most efficiently produce the remaining reserves of the field.

In the meantime, we have continued with our jointed pipe drilling operations using our own rigs and equipment and the directional drilling services of Baker Hughes International to drill horizontal sidetrack wells on the Ninotsminda Field. In October 2005 we completed the N100H2 sidetrack which tested at a rate of up to 13.07 MMcf (370 MCM) of gas per day plus 301 barrels of condensate per day (a total of 2,480 barrels oil equivalent[1]) on a 63/64 inch (25 mm) choke with a flowing tubing head pressure (FTHP) of 70 atmospheres (1,000 psig). The well is currently choked back as we await completion of repairs by the State owned gas transportation company to the 25 mile (41 Km) pipeline which is planned will deliver the gas from Ninotsminda to the local State-run thermal electricity generating station at Gardabani. A gas supply agreement was concluded in June 2006 with the expectation that sales would commence in September 2006, but repairs to the pipeline have not yet been completed and are unlikely to be completed in time to take delivery of gas during this Winter season.

The latest horizontal sidetrack well to be drilled on the field was the N97H well which we completed in March 2006. It targeted oil volumes un-drained from previous offset area wells and was put on production test following the installation of a slotted liner over a 1,509 feet (460 meters) interval furthest from the heel of the well. The well produced initially with a high water cut, approximately 70%, and an oil rate which peaked at 385 barrels of oil per day (bopd) before declining. Subsequent pressure surveys run with downhole gauges suggested that the N97H well was in communication with the offset N4H well. The most likely assumed scenario was then some of the fracture sets encountered at the end of the N97H well were drained by the N4H well and were hence water filled. Once a very high permeability connection is established with the aquifer, water will flow in preference to any oil filled fractures or matrix of lower permeability.

On the basis of the test data and due to the fact that the N97H well is approximately 36 feet (11 meters) structurally higher than the N4H well which is still producing oil, we decided to attempt to conduct remedial water isolation. The slotted liner deployed in the horizontal section limited mechanical options for shutting off the toe end of the horizontal section. Previous experience in the field has shown that pulling a liner once set has a very low chance of success due to formation collapse around the liner. Also, a traditional cement isolation was considered to have a low chance of success in a horizontal section, so we opted for a coiled tubing deployed chemical shut-off. Water isolation operations were conducted during the summer months but subsequent production testing showed that the treatment was not successful.

We now plan to set a cement retainer in the solid liner section of the N97H well in order to isolate and abandon the slotted liner part, but this operation has been significantly delayed awaiting delivery of the retainer. The liner through the heel section of the well will then be perforated and the well tested. The build up and heel section of the well is in a crestal location on the field and there has been little previous offset production.

In 2007, we plan to implement a modest work program aimed at maintaining and/or increasing production from the Ninotsminda Field. At the same time, we plan to complete a geological, geophysical and engineering re-evaluation of the field with a view to determining the best approach to developing the remaining reserves of the field. The eastern part of the field is largely un-drained with potentially significant remaining recoverable oil. This area represents approximately 30% of the entire structure as mapped and the only producing well in this part of the field is the N98 well which has produced 435,000 barrels of oil to date at a constant rate of 200 bopd

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since drilled in 1998, thus demonstrating the potential in this area. The selection of a drilling location will be based on the results of the planned technical study.

Kyzyloi

On the Kyzyloi Gas Field a development program is underway. The field contains sweet natural gas (97% methane) reservoired in shallow sandstones at a depth of approximately 1,640 feet (500 meters) which was discovered, but not developed, during the 1960 s. This field is located close to the Bukhara-Urals gas trunkline, and to the south of the Bozoi gas storage facility. BNM has carried out an extensive workover and testing program on the Kyzyloi Field wells, and the six wells tested to date for the initial development have flowed at a cumulative rate of over 24 MMcf (688 MCM) of gas per day. A gathering system, 32 mile (51 Km) pipeline and compressor station is in the process of construction to connect the Kyzyloi development to the Bukhara-Urals gas trunkline, with the initial planned production rate being 22 MMcf (625 MCM) per day and with first gas planned for late spring 2007. BNM believes that there is significant additional potential both in the Kyzyloi Field and in its surrounding Akkulka exploration contract area. As such the pipeline and associated facilities are being designed such that they could be upgraded to throughput up to 78 MMcf (2,200 MCM) per day of gas production.

Production from the Kyzyloi Field will be delivered under a natural gas supply contract concluded between BNM and Gaz Impex in January 2006. The contract, which has a term until June 2014, is based on a take-or-pay principle and covers all gas produced from the Kyzyloi Field Production Contract area. The delivery point under the contract will be the planned tie in point to the Bukhara-Urals gas trunkline. The price of gas at the delivery point averages $1.13 per Mcf ($32 per MCM) over the life of the contract, with Gaz Impex providing bank guarantees against payment.

BNM plans to invest approximately $5.8 million in the Kyzyloi development in 2007.

While a considerable amount of infrastructure for the Kyzyloi Field has already been put in place, and although tested gas wells exist on the Kyzyloi Field we cannot provide assurance that:

- funding of the development plan for the Field will be timely;
- formalisation of the Production Contract extension will be achieved;
- gas sales will operate according to the sales contract and at planned volumes;
- that the development plan will be successfully completed; or
- that operating revenues from the Field after completion of the development plan will exceed operating costs.

If crude oil and, to a lesser extent, natural gas prices return to depressed levels or if our production from our development program does not deliver a significant production increase, our revenues, cash flow from operations and financial condition will be materially adversely affected. For more information, see Liquidity and Capital Resources .

Exploration and Appraisal

Manavi

The first exploration well, Manavi 11 (M11), drilled on the Manavi structure reached a total depth (TD) of 14,765 feet (4,500 meters) in the Cretaceous in September 2003. The well encountered the Cretaceous limestone target at 14,265 feet (4,348 meters) with over 490 feet (150 meters) of hydrocarbons indicated on wireline logs and with no evidence of an oil-water contact present. On test the M11 well flowed light sweet 34.4ºAPI oil at a visibly significant rate and at a high pressure prior to the test being terminated due to the mechanical failure of the production tubing. Oil was also discovered in the shallower Middle Eocene sequence, but was not tested.

The well was prepared and subsequently sidetracked in a slim-hole using a Saipem S.p.A. (Saipem) Ideco E-2100Az drilling rig equipped with a top-drive drilling system, and an oil based mud system provided by

Baker-Hughes International (Baker) to control the swelling clays which had proved difficult to drill in the original well.

The Manavi M11Z well reached a TD of 14,994 feet (4,570 meters) in the Cretaceous in October 2005. The primary Cretaceous limestone target was encountered at 14,032 feet (4,277 meters) some 230 feet (70 meters) higher than in the original M11 well while the secondary Middle Eocene target zone was penetrated at 13,009 feet (3,965 meters) again significantly higher than in the M11 well. The carbonate section itself was proven to be approximately 980 feet (~300 meters) thick. Drilling data and slim hole wireline logs indicated the presence of hydrocarbons in both the Cretaceous and Middle Eocene target zones, again no oil water contact was identified.

Due to the small size of the well-bore and realising that this would not enable an optimal test of the structure, we decided to delay completion of this test until after the completion of the planned M12 appraisal well.

Drilling operations at the first appraisal site, M12 using the Saipem rig and Baker oil based mud services commenced on February 9, 2006, however, due to technical problems and having to sidetrack the well meant the well did not reach TD until mid-December 2006. The well was drilled to a depth of 16,762 feet (5,109 meters) in the Cretaceous interval with the top of the carbonate section being penetrated at 14,934 feet (4,552 meters). Significant hydrocarbon shows whilst drilling and wireline logs indicate a potentially significant hydrocarbon column in the well with no definitive presence of a hydrocarbon-water contact. The lower part of the carbonate section where a major gas influx occurred whilst drilling together with the underlying interbedded carbonates and tuffs appear to have the best reservoir characteristics. On setting the production liner, we planned to perform an initial short-term production test of the well prior to demobilizing the rig and then undertake a more comprehensive test as part of a longer-term production test after the site would be cleared and appropriate additional testing equipment installed.

An 886 feet (270 meter) 5 pre-perforated production liner was run over the section of the reservoir believed to have the better reservoir characteristics and a production testing string set to test the Cretaceous carbonate and interbedded units. During setting of the test string, the well began flowing and it was necessary to increase the mud weight to control the well whilst the test string was set. Despite the flow and gas observed at surface during drilling operations, the initial testing operations resulted in a pressure increase at surface but with no discernable flow. Subsequent re-perforating of parts of the test interval has resulted in minor flow with gas being flared and black 40.5^{o} API oil collected at surface. However it is considered likely that formation damage has occurred, probably whilst controlling the well during the setting of the test string, with mud penetrating and blocking the formation. Therefore stimulation techniques using acid to clean the well and create conductive pathways from the reservoir to the well-bore and hence bypass any reservoir damage will be required to fully production test the potential of the well. This is a fairly common procedure required in carbonate reservoirs in the area which produce prolifically in the North Caucasus.

On February 8, 2007 we announced that the Saipem drilling rig has now been demobilised from the M12 site and preparations have commenced for the acid stimulation of the reservoir and the resumption of the testing program. FracTech Ltd., a UK company providing independent well completion and stimulation laboratory testing, design and consultancy services, and Schlumberger well completions experts have been consulted and have advised on the chemicals for the test. These chemicals have been sourced in Germany by Schlumberger and are currently on route to Georgia. The stimulation itself will be performed through coiled tubing and this unit is already on site and has commenced cleaning the well in advance of spotting the acid. The acid treatment is expected to commence around the middle of March but, a number of acid treatments may be required which will take approximately two to three weeks to complete before the effectiveness of the stimulation can be determined. If the stimulation is successful, we will proceed to test the well with the aim of putting it into early production, however, if further stimulation is required, we would then plan to use hydraulic fracturing techniques in order to fully eliminate the potential formation damage. If the contingent hydraulic fracturing program is deemed to be required, it will be necessary to bring in specialist equipment to Georgia, and the Company is currently ascertaining the availability of such equipment.

Although management is excited about the potential of the Manavi prospect, a fair amount of additional drilling and analysis is still required before we will be able to fully evaluate the reserves and productive possibilities of this prospect. As part of this analysis,

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we are also evaluating the technical feasibility of acquiring a 3-D seismic data survey over the Manavi structure.

Given significant production is tested from the M12 well we would then proceed to test the M11z well, and would aim to place both wells on long term test production which would involve putting in place an early production facility.

Norio

The second phase of the preliminary work program under the Norio PSA commenced in January 2002 when the first exploration well named MK72 was spudded on the Norio prospect using the CanArgo Ural Mash rig. Norio is a large prospect identified at Middle Eocene level and is analogous in size to the nearby Samgori and Ninotsminda Field complex immediately to the south and east of the block. It has been reported that the Samgori Oil Field alone has produced approximately 180 million barrels of oil to date.

Completion of the MK72 well was delayed as a result of technical problems encountered whilst drilling, and the need to farm out a portion of the equity in the block in order to partly fund the drilling. In September 2003, CNL signed a farm-in agreement relating to the Norio PSA with a wholly owned subsidiary of Georgian Oil, the Georgian State Oil Company. This farm-in agreement obligated Georgian Oil to pay up to $2.0 million to deepen, to a planned depth of 16,733 feet (5,100 meters) the MK-72 well in return for a 15% interest in the contractor share of the Norio PSA. Georgian Oil also had an option, exercisable for a limited period after completion of the well, to increase its interest to 50% of the contractor share of the Norio PSA on payment to CNL of $6.5 million. Due to Georgian Oil s inability to continue to fund the drilling of the well, operations were subsequently suspended and only resumed after May 2005 when we repaid to Georgian Oil the investment it had made in the MK72 well to terminate the farm-in agreement and option and secure a 100% working interest in the Norio PSA.

In August 2005 the Saipem drilling rig and Baker oil-based mud system was mobilized to the MK72 exploration well as our Ural Mash rig had difficulty drilling through a highly over-pressured section of swelling clays above the prognosed target zone. On December 29, 2005, we announced that the MK72 well reached a depth of 16,076 feet (4,900 meters) in the Middle Eocene reservoir having encountered very good oil and gas shows. Before the well could be drilled to the planned depth and tested, the bottom hole assembly (BHA) became stuck due to hole collapse. Subsequent attempts to retrieve the BHA were not successful and we decided to abandon the lower target due to a limited chance of sidetracking the well at this depth in a small diameter hole and to focus our attention on the shallower oil discovery in the overlying Oligocene sands which were the secondary target for the well. From the data obtained from the Middle Eocene (the primary target for the well) we believe that an oil discovery has been made at this level, and that the reservoir has exhibited both permeability and the presence of movable light oil. As such, even though the Middle Eocene has not been fully evaluated, the MK72 well has encountered the Middle Eocene reservoir on prognosis, and with hydrocarbons thus achieving many of the objectives of this wildcat exploration well.

A comprehensive testing program on the oil bearing Oligocene sandstones encountered in the Norio MK72 well commenced in mid-March 2006 when a total of 322 feet (98 meters) of net sands were perforated over the interval 12,096 feet (3,687 meters) to 13,622 feet (4,152 meters). These sands had good oil shows whilst drilling, with oil to surface and with hydrocarbons being interpreted on the electric logs which also indicated a substantial thickness of net pay sands. Following an extensive testing program, the well sustained flow on a small choke size with low average gross fluid rates of approximately 13 barrels per day consisting of light 48.6ºAPI oil, gas and water.

A number of surge clean up flows, a re-perforation of selected intervals, and a low pressure hydrofrac using our own pumping unit have been attempted but these have not improved reservoir deliverability. It is believed that the current flow is limited to a thinner, less permeable, interval whilst the better quality reservoir remains isolated due to potential reservoir damage caused by the invasive fluid damage of the drilling mud. The lower zones in the well, which would have been in communication with the Oligocene interval through the well-bore, were drilled with a 1.9 to 2.2 Specific Gravity (SG) mud due to anticipated reservoir pressures while the results from the testing program indicate that the mid interval reservoir pressure for the Oligocene whilst still over pressured, is lower at 1.7 SG equivalent.

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As a result of possible mud damage, the current perforations may have not penetrated deep enough beyond the damaged zone to allow proper communication between the more permeable formations and the well-bore.

We considered mobilising a more powerful fraccing unit and equipment to Georgia in order to pump a propant and fluid into the well at high pressure and volume, but the potential for this technology is limited due to a lack of a cement bond behind the casing and the large interval which has been perforated. The well has been left on test production for the past several months but there has been no discernable increase in gross fluid production rate. As we would appear to have exhausted all the low cost options available to us at this time to bypass any damage that may exist in the near-well-bore area and establish better communication between the well-bore and the reservoir, we believe that the only effective option remaining is to sidetrack the well or to drill a new well. The latter, of course, would enable us to attempt to test both the Oligocene and Middle Eocene intervals both of which are considered to have significantly reduced geological risk.

We plan, subject to financing being available from internal resources or through a farm out arrangement, to drill an appraisal well to fully evaluate these attractive discoveries, with the well being designed to enter the Middle Eocene reservoir with a larger hole size.

Kumisi

In February 2007, we announced that we had commenced drilling an appraisal well, Kumisi #1, on the Kumisi gas prospect within the Nazvrevi / Block XIII PSC area. A gas discovery was made in the Cretaceous in the WRK16 well in Soviet times but never appraised. The prospect which is potentially of very significant size is situated up-dip of the WR16 well with the principal risk being closure on the structure. This prospect is located approximately 7.5 miles (12 Km) southeast of Tbilisi and is close to the domestic gas infrastructure and the route of the new South Caucasus gas trunkline from Azerbaijan to Turkey, and is approximately 12.5 miles (20 Km) west of the Gardabani thermal power plant and Rustavi industrial complex.

On March 3, 2006 we announced that our subsidiary, CanArgo (Nazvrevi) Limited (CNZ) has signed a Memorandum of Understanding (MOU) with the Georgian Government which includes the terms of a take-or-pay natural gas supply contract relating to gas sales from the Kumisi gas prospect within the Nazvrevi / Block XIII PSC area. The gas supply contract will be with the Georgian State, secured against appropriate bank guarantees, in which CNZ will supply gas from Kumisi based on a pricing formula under which gas is initially supplied at a contract price of $1.56 per Mcf ($55 per MCM), increasing to $2.28 per Mcf ($80 per MCM) by the tenth contract year, after which escalation will be based on European Union heavy fuel oil price changes. The contract will be for the entire field life. However, after the tenth year, CNZ has the option of selling to third parties if the price obtained is 10% above the contract price at that time.

The well which is being drilled with CanArgo Rig #2 is expected to reach total depth of 12,140 feet (3,700 meters) in the Cretaceous by late June. Surface casing has been set at a depth of 1,004 feet (306 meters) and the well is currently drilling ahead at approximately 4,921 feet (1,500 meters) in the Middle Eocene.

In 2007, we have budgeted approximately $4.6 million for our exploration and appraisal work in Georgia, primarily for the testing and appraisal of the Manavi discovery and drilling the Kumisi well.

Akkulka & Greater Akkulka

In 2005 / early 2006 BNM undertook a five well exploration program targeting shallow gas anomalies which may be similar to the Kyzyloi Field within the Akkulka Exploration Contract Area. All five of these wells had gas indications on wireline logs and to date two have been fully production tested, namely AKK04 and AKK05. The AKK05 well, located 4 miles (6.5 Km) north east of the Kyzyloi Field, flowed gas at a rate of 7.9 MMcf (223 MCM) per day. This well effectively extended the Kyzyloi Field to the north east, including an untested fault block (NE Kyzyloi), and work is currently underway with respect to extending the area of the Kyzyloi Production Contract to include the AKK05 well which will be included as a production well in the Kyzyloi Field development. The AKK04 exploration well, located some 12.5 miles (20 Km) east of the Kyzyloi Field, flowed gas at a stabilized flow rate of 8.8 MMcf (250 MCM) of gas per day, and this well, now named

Central Akkulka, has been declared a commercial discovery by BNM. An appraisal / exploration well (AKK06) was drilled by BNM late in 2006 to appraise and extend the Central Akkulka accumulation to the south west. This well had gas indications on the wireline logs but remains to be tested as part of an integrated testing program currently underway. It is planned to tie the AKK04 discovery into the Kyzyloi development, initially by way of a long term extended well test, but then by the application for a separate production contract, once the Central Akkulka accumulation has been fully evaluated.

In the other three exploration wells which have been drilled to date, AKK01, AKK02 and AKK03, gas indications were observed during drilling and in thin sands on wireline logs. These sands are present at several stratigraphic levels within the wells. AKK01 lies to the north east of the Kyzyloi Field on a prospect named North Akkulka. Testing of the AKK01 well is planned for Q2 2007 as part of the current integrated testing program. The AKK02 and AKK03 wells lie to the south east of the Kyzyloi Field on a prospect named South Akkulka. AKK03 is up-dip of AKK02 and encountered a gas bubble whilst drilling and with gas being noted on the wellhead. This well is currently being fully tested. The downdip well AKK02, which has thin sandstones showing possible gas on wireline logs but with relatively high water saturations, was tested and flowed water from these sands, this well therefore delineating the downdip extent of the South Akkulka at this level (although higher untested sands do exist) prospect which remains to be tested for commercial flow by the AKK03 well.

Further exploration continues on the Akkulka block with four more wells planned for 2007. Currently the AKK07 (South West Akkulka) well is drilling and is currently at a depth of 902 feet (275 meters).

BNM plans to invest approximately $3.0 million on the Akkulka Exploration Contract Area during 2007.

On the Greater Akkulka Exploration and Production Contract Area initial seismic mapping has shown the presence of additional potential shallow gas prospects at similar levels to those on Akkulka, and with some slightly deeper plays. Additional 2D seismic data is being acquired this year on the Greater Akkulka Contract Area as part of the work commitment under the contract and to infill the western part of the area prior to the contractual relinquishment of 20% of the area at the end of 2007. A seismic contractor has been selected and work is expected to commence in the summer of 2007.

BNM plans to invest approximately $1.1 million on the Greater Akkulka Contract Area during 2007.

To pursue existing projects beyond our immediate development plan and to pursue new opportunities, we will require additional capital. While expected to be substantial, without further exploration work and evaluation the exact amount of funds needed to fully develop all of our oil and gas properties cannot at present, be quantified. Potential sources of funds include additional sales of equity securities, project financing, debt financing and the participation of other oil and gas entities in our projects. Based on our past history of raising capital and continuing discussions, management believes that such required funds may be available. However, there is no assurance that such funds will be available, and if available, will be offered on attractive or acceptable terms. Should such funding not be forthcoming and we are unable to sell some or all of our non-core assets, or, if sold, such sales realize insufficient proceeds; we may have to delay or abandon such projects.

Development of the oil and gas properties and ventures in which we have interests involves multi-year efforts and substantial cash expenditures. Full development of our oil and gas properties and ventures will require the availability of substantial additional financing from external sources. We may also, where opportunities exist, seek to transfer portions of our interests in oil and gas properties and ventures to entities in exchange for such financing. We generally have the principal responsibility for arranging financing for the oil and gas properties and ventures in which we have an interest. There can be no assurance, however, that we or the entities that are developing the oil and gas properties and ventures will be able to arrange the financing necessary to develop the projects being undertaken or to support our corporate and other activities. There can also be no assurance that such financing as is available will be on terms that are attractive or acceptable to or are deemed to be in the best interest of CanArgo, such entities and their respective stockholders or participants.

Ultimate realization of the carrying value of our oil and gas properties and ventures will require production of oil and gas in sufficient quantities and marketing such oil and gas at sufficient prices to provide positive cash flow to us. Establishment of successful oil and gas operations is dependent upon, among other factors, the following:

- mobilization of equipment and personnel to implement effectively drilling, completion and production activities;
- raising of additional capital;
- achieving significant production at costs that provide acceptable margins;
- reasonable levels of taxation, or economic arrangements in lieu of taxation in host countries; and
- the ability to market the oil and gas produced at or near world prices.

Subject to our ability to raise additional capital, we have plans to mobilize resources and achieve levels of production and profits sufficient to recover the carrying value of our oil and gas properties and ventures. However, if one or more of the above factors, or other factors, are different than anticipated, these plans may not be realized, and we may not recover the carrying value of our oil and gas properties and ventures.

Commencing in July 2009 through July 2010 an aggregate of $53 million in indebtedness under the Company s Senior Secured Notes, the Subordinated Notes, the 12% Subordinated Notes and the Tethys Bridge Financing (collectively, the Notes) will come due and be payable. Unless such Notes are converted into shares of common stock in accordance with their respective terms, the Company will be required to repay or refinance such outstanding indebtedness. There can be no assurance at this time that Company will have the resources to repay such Notes or if it will be in a position to refinance such indebtedness. The Notes are secured by all the assets of the Company.

Availability of Capital

As described more fully under Liquidity and Capital Resources below, our sources of capital are primarily cash on hand, cash from operating activities, project financing, debt financing, the participation of other oil and gas entities in our projects, and the proceeds from the sale of certain assets. We may also attempt to raise additional capital through the issuance of debt or equity securities although no assurances can be made that we will be successful in any such efforts.

As of February 28, 2007, the Company had an aggregate of 238,487,390 shares of common stock issued and outstanding and 375,000,000 authorized shares of common stock. During 2006, we issued 14,559,107 shares of our common stock of which 1,521,739 shares were in connection with the conversion of a Convertible Loan, 774,000 shares were in connection with exercise of stock options and 12,263,368 shares were in connection with a private placement. During 2007, we have to date issued 1,000,000 shares of our common stock in connection with an exercise of warrants and 355,000 shares in connection with an exercise of employee stock options. . As of March 9, 2007, an aggregate of 96,010,214 shares are reserved for issuance under various stock option plans, warrants and other contractual commitments, including the Senior Secured Notes, the Subordinated Notes and the 12% Subordinated Note.

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Liquidity and Capital Resources

General

The crude oil and natural gas industry is a highly capital intensive and cyclical business. Our current capital requirements are driven principally by our obligations to fund the following costs:

- the development of existing properties, including drilling and completion costs of wells; and
- acquisition of interests in crude oil and natural gas properties.

The amount of capital available to us will affect our ability to continue to grow the business through the development of existing properties and the acquisition of new properties and, possibly, our ability to service any future debt obligations, if any. Our sources of capital are primarily cash on hand, cash from operating activities, project financing, debt financing, the participation of other oil and gas entities in our projects, and the sale of certain assets. Our overall liquidity depends heavily on the prevailing prices of crude oil and natural gas and our production volumes of crude oil and natural gas. We do not hedge our crude oil production. Accordingly, future crude oil and, to a lesser extent, natural gas price declines would have a material adverse effect on our overall results, and therefore, our liquidity. Low crude oil and natural gas prices could also negatively affect our ability to raise capital on terms favorable to us and could also reduce our ability to borrow in the future. If the volume of crude oil we produce decreases, our cash flow from operations will decrease. Our production volumes will decline as reserves are produced. We sold properties in 2003 and 2004 which reduced potential future reserves and in the future, we may sell additional properties and other assets, which could further reduce our production volumes and income from oil well drilling and servicing. To offset the loss in production volumes resulting from natural field declines and sales of producing properties, we must conduct successful exploration, exploitation and development activities, acquire additional producing properties as we did with our acquisition of a 50% interest in the Samgori Field in 2004 or identify additional behind-pipe zones or secondary recovery reserves.

Should our current exploration, exploitation and development wells in Georgia prove unsuccessful and we were unable to raise additional debt or equity finance, we might have to cut back on our capital spending plans and or modify our operating plans to conserve cash.

As of December 31, 2006, we had working capital of $11,628,000 compared to working capital of $14,808,000 as of December 31, 2005. The $3,180,000 decrease in working capital from December 31, 2005 to December 31, 2006 is principally due to expenditures in the period to fund the cost of preparing wells for our horizontal development program at the Ninotsminda Field, the appraisal of our Manavi oil discovery in Georgia, activities in Kazakhstan and net cash used by operating activities partially offset by cash received pursuant to the Subordinated Notes, the 12% Subordinated Notes, the Tethys Bridge financing, the sale of an aggregate of 12,263,368 shares of common stock in October 2006, in an offshore private placement in Norway pursuant to Regulation S promulgated by the SEC (the Reg. S Offering) and the maturing of deposits previously recorded as restricted cash.

In May 2004, NOC entered into a crude oil sales agreement with Primrose Financial Group (PFG) to sell its monthly share of oil produced under the Ninotsminda production sharing contract with a total contractual commitment of 84,000 metric tonnes (636,720 bbls). As security for payment and having the right to lift up to 8,400 metric tonnes (approximately 64,000 bbls) of oil per month, the buyer caused to be paid to NOC $2,300,000 (Security Deposit) to be repaid at the end of the contract period either in money or through the delivery of additional crude oil equal to the value of the security. The Security Deposit replaced the previous security payments totalling $2,300,000 which had been originally made available under previous oil sales agreements.

On February 4, 2005, NOC and PFG agreed to the terminate the Sales Agreement and enter into a new agreement (New Agreement) whereby PFG would receive an immediate repayment of its Security Deposit and obtain an extended term over which it can purchase crude oil produced from the Ninotsminda Field while NOC receives better commercial terms for the sale of its production. The New Agreement had a minimum term of 45 months.

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Certain Asset Sales

In 2003, we signed a sales agreement disposing of a 3-megawatt duel fuel power generator for $600,000 and received a non-refundable deposit of approximately $300,000. The unit was shipped to the United States where it underwent tests in late 2004. On completion of these tests to the satisfaction of the buyer, we were to transfer title for this equipment and receive the final payment of $300,000. Although the unit was successfully tested, the buyer failed to meet the sale contract terms resulting in the loss of its deposit in the third quarter, 2005. We are currently remarketing the generator but impaired it by $600,000 to nil in the fourth quarter of 2006.

On May 28, 2004, we announced that pursuant to a signed agreement between CanArgo Acquisition Corporation, our wholly owned subsidiary, and Stanhope Solutions Ltd., we had completed a transaction to sell our interest in the Bugruvativske Field in Ukraine through the disposal of our wholly owned subsidiary, Lateral Vector Resources, for $2,000,000. We received $250,000 as an initial payment and will receive the remaining $1,750,000 based upon certain production targets being achieved on the project. As of December 31, 2006, no additional payments have been made.

Financing

On February 11, 2004, we entered into a Standby Equity Distribution Agreement (SEDA) that allowed us, at our option, periodically to issue shares of our common stock to US-based investment fund Cornell Capital Partners, LP (Cornell Capital) up to a maximum value of $20,000,000 (Cornell Facility). Under the terms of the SEDA, Cornell Capital provided us with an equity line of credit for 24 months from the Effective Date (as defined in the SEDA). The maximum aggregate amount of the equity placements pursuant to the SEDA was $20,000,000. Subject to this limitation, we could draw down up to $600,000 in any seven-day trading period (a Put). The Cornell Facility could be used in whole or in part entirely at our discretion, subject to effective registration of the shares under the Securities Act. Shares issued to Cornell Capital were priced at a 3% discount to the lowest daily Volume Weighted Closing Bid Price (VWAP) of CanArgo common shares traded on the Oslo Stock Exchange (OSE) for each of the five consecutive trading days immediately following a draw down notice by CanArgo. For each share of common stock purchased under the SEDA, Cornell Capital received a substantial discount to the current market price of CanArgo common stock. The level of the total discount varied depending on the market price of our stock and the amount drawn down under the SEDA. On the basis of the average high and low price for common stock as reported on the American Stock Exchange on January 27, 2005 of $1.37, Cornell Capital received a total discount of 13.87% to the market price of our stock. Such discount comprised (1) 3% discount to, the lowest volume weighted average price of our common stock; (2) 5% of the proceeds that we received for each advance under the SEDA; and (3) a commitment fee of 5.87%. The commitment fee, which was paid, consisted of $10,000 in cash (paid in two tranches) and 850,000 shares of our common stock (issued in three tranches). The 850,000 shares of common stock issued in respect of the commitment fee represented nearly 4% of the estimated 23 million shares of common stock that could have been issued by us under the SEDA. In February 2004, we engaged Newbridge Securities Corporation, a registered broker dealer, to advise us and to act as our exclusive placementagent in connection with the Cornell Facility pursuant to the Placement Agent Agreement dated February 11, 2004. For its services, Newbridge Securities Corporation received 30,799 restricted shares of our common stock which were included in the Registration Statement on Form S-3 (Reg. No. 333-115261) filed on May 6, 2004. On February 3, 2005, the SEC declared effective the registration statement on Form S-3 (Reg. No. 333-115261) originally filed by us on May 6, 2004 in respect of the shares issuable under the Cornell Facility.

On February 21, 2005, we sold 380,836 shares of CanArgo common stock at $1.31 per share under the Cornell Facility. The proceeds of this sale of $500,000 were used to reduce the promissory note to Cornell Capital from $1,500,000 to $1,000,000.

On February 28, 2005, we sold 335,653 shares of CanArgo common stock at $1.47 per share under the Cornell Facility. The proceeds of this sale of $500,000 were used to reduce the promissory note to Cornell Capital from $1,000,000 to $500,000. The proceeds included additional proceeds attributable to 5,179 shares of

CanArgo common stock issued pursuant to the takedown under the Equity Line completed on February 21, 2005 proceeds of which should have been credited to us under the February 21, 2005 draw down.

On March 7, 2005, we sold 344,758 shares of CanArgo common stock at $1.54 per share under the Cornell Facility. The interest owed on the note of $32,548 was included in the proceeds. The proceeds of this sale of $500,000 were used to reduce the promissory note to Cornell Capital from $500,000 to $0.

On March 14, 2005, we sold 370,599 shares of CanArgo common stock at $1.62 per share under the Cornell Facility. This provided net proceeds of $600,000 to CanArgo.

On April 26, 2005 we signed a promissory note with Cornell Capital whereby Cornell Capital agreed to advance us the sum of $15 million (Promissory Note). Pursuant to the terms of the Promissory Note the $15 million and interest at a rate of 7.5% per annum was repayable either in cash or using the net proceeds of drawdowns under the SEDA, within 270 calendar days from the date of the Promissory Note. Pursuant to the terms of the Promissory Note, we escrowed 25 requests for advances under the SEDA each in an amount not less than $600,000 and one advance of $289,726.03 (representing estimated interest) together with 16,938,558 shares of CanArgo common stock. As at the agreement date, 664,966 shares were already in escrow.The escrow agent released requests every 7 calendar days from May 2, 2005 provided we had not previously made a payment to Cornell Capital in cash. We had the ability at our sole discretion upon 24 hours prior written notice to Cornell Capital to repay all and any amounts due under the Promissory Note in immediately available funds and withdraw any advance notices yet to be effected.

On August 1, 2005, we made a payment of $7,422,410.96 being the outstanding principal and accrued interest amount payable to Cornell Capital under the terms of both the SEDA and the Promissory Note. Furthermore, all escrowed advances were cancelled and 7,260,647 shares of CanArgo common stock were returned from escrow and duly cancelled on October 5, 2005. In accordance with Section 6 of the Promissory Note, upon receipt of such outstanding sums the Promissory Note was deemed cancelled. On July 25, 2005 notice was given to Cornell Capital to terminate the SEDA with effect as of August 24, 2005.

We received $12,332,548 proceeds net of $285,749 of discounts (excluding the commitment fee of $10,000 and 850,000 shares of common stock previously paid to Cornell Capital) pursuant to twenty one takedowns under the SEDA in which we issued a total of 13,012,945 shares of our common stock to Cornell Capital at an average price of $0.9477 per share. From these proceeds, $1,532,548 was used to repay the promissory note of $1,500,000 plus accrued interest on the note of $32,548 to Cornell Capital and partially repay the promissory note of $15,000,000.

On July 25, 2005, we announced that we had closed the private placement of a $25,000,000 issue of Senior Secured Notes due July 25, 2009 (Senior Secured Notes) with a group of investors arranged through Ingalls & Snyder LLC of New York City.

The proceeds of this financing, after the payment of all professional and placing expenses and fees, had been used to redeem short term debt and accrued interest in the amount of approximately $7,400,000 under the Promissory Note with Cornell Capital, to fund the appraisal of a new gas project in Georgia, to fund the development of the Kyzyloi Gas Field in Kazakhstan and adjacent exploration areas, and for additional working capital for our development, appraisal and exploration activities in Georgia. In addition, we terminated the SEDA which we had with Cornell Capital with effect as of August 24, 2005.

See Note 11 to the consolidated financial statements included herein for a description of the terms and conditions of the Senior Secured Notes.

On March 3, 2006, we finalised a private placement with a limited group of investors arranged by Ingalls & Snyder LLC of New York City of a $13,000,000 issue of Senior Subordinated Convertible Guaranteed Notes due September 1, 2009 (the Subordinated Notes) and warrants to purchase an aggregate of 13,000,000 shares of our common stock (Subordinated Note Warrant Shares) at an exercise price of $1.37 per share, subject to adjustment, and expiring on March 3, 2008 or sooner under certain circumstances (Subordinated Note Warrants).

The proceeds of this financing, after the payment of all placing expenses and professional fees were used exclusively to fund the development of the Kyzyloi Gas Field in Kazakhstan and on the commitment exploration programs in Kazakhstan through Tethys, the wholly owned subsidiary of CanArgo which holds CanArgo s Kazakhstan assets.

See Note 11 to the consolidated financial statements included herein for a description of the terms and conditions of the Subordinated Notes and associated Subordinated Note Warrants.

On June 28, 2006, we announced that we had entered into the private placement with Persistency of a $10,000,000 issue of a 12% Subordinated Convertible Guaranteed Note due June 28, 2010 (the 12% Subordinated Note) and warrants to purchase an aggregate of 12,500,000 shares of CanArgo common stock (12% Note Warrant Shares), at an exercise price of $1.00 per share, subject to adjustment, and expiring on June 28, 2008 or sooner under certain circumstances (the 12% Note Warrants).

The proceeds of this financing, after the payment of all placing expenses and professional fees were used to fund our appraisal and development activities in Georgia including further development of the Ninotsminda Field and appraisal of the Kumisi gas discovery.

See Note 11 to the consolidated financial statements included herein for a description of the terms and conditions of the 12% Subordinated Note and associated 12% Subordinated Note Warrants.

On September 7, 2006 we announced that Tethys had completed a $5 million interim loan financing (the Tethys Bridge) to fund Tethys development activities in Kazakhstan ahead of Tethys intended spin-off and admission to the AIM market in London. The funds were used by Tethys primarily for the purchase of pipeline, compressors and related equipment and services for the Kyzyloi field development. The financing took the form of the issue of $5 million senior secured notes in Tethys redeemable on August 31, 2008 (the Tethys Notes) pursuant to a note and warrant or royalty purchase agreement dated September 5, 2006 (the Tethys NPA). Pursuant to the Tethys NPA, Tethys has the ability to pre-pay the Tethys Notes and the Tethys Notes fall to be automatically pre-paid in full following a change of control of Tethys which includes the admission of Tethys to AIM or a recognised stock exchange. Tethys has granted security over its bank account with HSBC Bank plc and its shareholding in its wholly owned subsidiary, Tethys Kazakhstan Limited, as a condition of the Tethys NPA with such security to be released on repayment of the funds. The Tethys Notes bear interest at the rate of 10% per annum for the period from the date of issue until December 31, 2006 and 15% per annum from January 1, 2007 until they are repaid in full. The Tethys NPA contains certain affirmative and negative covenants on Tethys which apply provided at least $500,000 in aggregate of the Tethys Notes is outstanding. The affirmative and negative covenants require Tethys among other things to maintain its corporate existence, to maintain insurance coverage on such terms and in such amounts as is customary in the case of entities in the same or similar businesses and which are similarly situated, to keep current with respect to payment of all due and payable taxes, to not permit Tethys to engage in transactions with affiliates unless they are in the ordinary course of business and on arm s length terms, to not enter into mergers or consolidations while an default or event of default is continuing or to allow liens on any pledged or secured assets under the NPA except specified permitted liens. In addition, while the covenants still apply Tethys must seek the permission of the noteholders to incur additional external third-part indebtedness in excess of $2,500,000 except permitted indebtedness as specified in the Tethys NPA.

Pursuant to the provisions of Emerging Issue Task Force 86-15: Increasing-Rate Debt , the Company recognizes interest expense using the effective interest rate method, which results in the use of a constant interest rate for the life of the Tethys Notes. The effective interest rate is approximately 14.2% per annum. The difference between the interest computed using the actual interest rate in effect (10% per annum to December 31, 2006 and 15% from January 1, 2007) and the effective interest rate (14.2% per annum) totalled $66,715 as of December 31, 2006 of which $35,000 has been included in accrued liabilities and $31,715 has been accrued as a non-current liability.

Under the terms of the Tethys NPA, the holders of the Tethys Notes are entitled to receive additional consideration for the advance of the loan in the form of either (1) at closing of the fundraising, warrants to subscribe for ordinary shares in the capital of Tethys (the Tethys Warrants) or (2) 90 days following first commercial sale of hydrocarbons, in which case Tethys may chose between granting the noteholder Tethys Warrants or entering into a royalty agreement with the noteholder. The Tethys Warrants shall be issued pursuant to the terms of an instrument by way of deed poll entered into by Tethys on September 5, 2006. The Tethys Warrants are exercisable in whole or in part at any time up to the expiry of 60 months from the date of the

Tethys NPA. As of December 31, 2006, the number of ordinary shares in the capital of Tethys into which the Tethys Warrants are exercisable and the exercise price of the Tethys Warrants are based on an assumed valuation of Tethys, however, in the event of an AIM or other listing prior to July 31, 2007 the number of shares and exercise price change to become based on the listing price and valuation of the AIM listing. One of the noteholders elected to receive their Tethys Warrants at the closing of the fundraising. The other noteholder shall receive their additional consideration 90 days from first commercial sale of hydrocarbons by Tethys.

The requisite holders of the Secured Notes, Subordinated Notes and 12% Subordinated Notes provided their consent to the Tethys Bridge as required under their respective Note Purchase Agreements.

The Tethys NPA, Tethys Notes, Tethys Warrants and the Warrant Instrument are governed by English law.

On October 13, 2006, we announced the completion of a private placement in Norway by way of the issue of an aggregate of 12,263,368 shares of common stock at a purchase price of NOK 9.10 per share (the Reg. S Shares) for aggregate gross proceeds of NOK 111,596,239 ($16,687,039 equivalent based upon a conversion rate of NOK 6.6876 per dollar) before placing fees and expenses estimated at NOK 6,695,774 ($1,001,022). The shares were issued in a transaction intended to qualify for the exemption from registration afforded by Section 4(2) of the Securities Act and Regulation S promulgated thereunder. CanArgo agreed to register the Shares for resale under the Securities Act and the Company filed a Registration Statement on Form S-3 with the SEC on October 13, 2006, which included these shares. The Registration Statement on Form S-3 was declared effective on January 19, 2007. As a result of the delays incurred in registering the Shares we have paid subscribers a cash liquidity penalty of 5% of the subscription price of their Shares in the aggregate amount of NOK 5,579,812 ($834,352 equivalent). The net proceeds of the placement will be used by the Company for working capital; future capital expenditures in Georgia, including, without limitation, securing drilling equipment; and other related activities.

The Next Twelve Months

In February 2007 we announced that TPL had completed a private placement with a limited group of private investors raising gross proceeds of approximately $17.35 million, by issuing in total approximately 34.7 million new ordinary shares in TPL (representing approximately 33% of the issued and outstanding share capital of TPL) and with CanArgo Limited (a wholly owned subsidiary of CanArgo) retaining our 70,000,000 shares in TPL (representing the remaining 67%). Under the terms of the Shareholders Agreement entered into with the new private investors (the Investors), TPL is subject to certain positive and negative covenants which require the consent of the holders of not less than 75% of the ordinary shares in issue in TPL from time to time (the Shareholder Majority). The Agreement also outlines certain provisions in relation to the conduct of the TPL business and provided that the intention of TPL, CanArgo Limited and the Investors is to use their reasonable endeavors to work towards a listing of TPL as soon as practicable, subject to (i) the financial and commercial circumstances of TPL, and the pre-money valuation of TPL prior to the listing being acceptable to the Shareholder Majority; and (ii) the terms and amounts (if any) raised by TPL on such listing being acceptable to the board of TPL.

Agreement has now also been reached whereby, subject to any required Kazakh regulatory approvals Tethys, through its wholly owned subsidiary Tethys Kazakhstan Limited (TKL) will acquire the 30% of BNM it does not own in return for 30 million shares in Tethys, and making BNM a wholly owned subsidiary of TKL. TKL s interest in BNM is currently the principal asset of Tethys. Following this share swap there will be approximately 134.7 million shares in Tethys of which CanArgo will own 70 million (52 %).

Cash flows from the TPL private placement mean we have most of the working capital necessary to cover our immediate and near term funding requirements in relation to our activities in Kazakhstan only. In order to continue with all of our currently planned development activities in Georgia on our Ninotsminda Field and the appraisal of our Manavi oil discovery, and our exploration and development plans in Kazakhstan, we are currently investigating further fundraising proposals.

On June 28, 2006 we announced that Tethys was intending to seek admission to the AIM market of the London Stock Exchange and raise funds for its development and exploration activities in Kazakhstan (Tethys Spin-Out). We planned to retain a significant, but not controlling, equity interest in Tethys after the admission of Tethys to the AIM market. The intention was that this funding would enable the Kazakh assets to be financed whilst minimizing dilution for our shareholders and potentially raising additional funds for our operations. Tethys engaged ODL Securities Limited to act as principal broker for this transaction, which was planned for the end of 2006, subject to prevailing market conditions. In view of market conditions, our brokers were unable to indicate that sufficient capital would be raised to fulfil the capital required to proceed with the AIM admission as planned.

Tethys has now entered into an Engagement Letter with Jennings Capital Inc. of Calgary, Alberta (JCI) engaging JCI to act as lead agent with respect to a planned initial public offering (IPO) and listing of Tethys on the Toronto Stock Exchange (TSX) later this year. In addition McDaniel and Associates Consultants Limited have been engaged to carry out an independent evaluation of Tethys projects in connection with the proposed listing. The full details of the planned IPO have yet to be finalised.

While a considerable amount of infrastructure for the Ninotsminda Field has already been put in place, we cannot provide assurance that:

- funding of a field development plan will be timely;
- that our development plan will be successfully completed or will increase production; or
- that field operating revenues after completion of the development plan will exceed operating costs.

Under the terms of each of the Note issues, we are restricted from incurring future indebtedness and from issuing additional senior or *pari passu* indebtedness, except with the prior consent of the Required Holders or in limited permitted circumstances. The definition of indebtedness encompasses all customary forms of indebtedness including, without limitation, liabilities for the deferred consideration, liabilities for borrowed money secured by any lien or other specified security interest, liabilities in respect of letters of credit or similar instruments (excluding letters of credit which are 100% cash collateralised) and guarantees in relation to such forms of indebtedness (excluding parent company guarantees provided by the Company in respect of the indebtedness or obligations of any of the Company s subsidiaries under its Basic Documents (as defined in the respective Note Purchase Agreements). Pursuant to the terms of the Note Purchase Agreements, permitted future indebtedness is (a) indebtedness outstanding under the Notes; (b) any additional unsecured indebtedness, the aggregate amount outstanding thereunder at any time not exceeding certain specified amounts and; (c) certain unsecured intra-group indebtedness (in the case of Senior Secured Notes, Subordinated Notes and 12% Subordinated Notes this is limited to the indebtedness of a CanArgo Group Member (as defined in the relevant Note Purchase Agreements) to a direct or indirect subsidiary of the Company which is not deemed to be a Material Subsidiary (under the Note Purchase Agreements the aggregate amount outstanding under the particular indebtedness shall not exceed certain specified levels at any time). See Note 11 to the consolidated financial statements included herein.

To pursue existing projects for our immediate appraisal and development plans, pay operating expenses and to pursue new opportunities, we will require additional capital in the second quarter of 2007. While expected to be substantial, without further exploration work and evaluation the exact amount of funds needed to fully develop all of our oil and gas properties cannot at present, be quantified. Potential sources of funds include additional sales of equity securities, project financing, debt financing and the participation of other oil and gas entities in our projects. Based on our past history of raising capital and continuing discussions, we believe that such required funds may be available. However, there is no assurance that such funds will be available, and if available, will be offered on attractive or acceptable terms. Should such funding not be forthcoming, we may not be able to pursue projects beyond our current appraisal and development plans or to pursue new opportunities. As discussed above, under the terms of the Notes, we are restricted from incurring additional indebtedness.

Development of the oil and gas properties and ventures in which we have interests involves multi-year efforts and substantial cash expenditures. Full development of our oil and gas properties and ventures may require the availability of substantial additional financing from external sources. We may also, where opportunities exist, seek to transfer portions of our interests in oil and gas properties and ventures to entities in exchange for such financing. We generally have the principal responsibility for arranging financing for the oil and gas properties and ventures in which we have an interest. There can be no assurance, however, that we or the entities that are developing the oil and gas properties and ventures will be able to arrange the financing necessary to develop the projects being undertaken or to support the corporate and other activities of CanArgo. There can also be no assurance that such financing will be available on terms that are attractive or acceptable to or are deemed to be in the best interest of CanArgo, such entities and their respective stockholders or participants.

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Ultimate realization of the carrying value of our oil and gas properties and ventures will require production of oil and gas in sufficient quantities and marketing such oil and gas at sufficient prices to provide positive cash flow to CanArgo. Establishment of successful oil and gas operations is dependent upon, among other factors, the following:

- mobilization of equipment and personnel to implement effectively drilling, completion and production activities;
- raising of additional capital;
- achieving significant production at costs that provide acceptable margins;
- reasonable levels of taxation, or economic arrangements in lieu of taxation in host countries; and
- the ability to market the oil and gas produced at or near world prices.

Subject to our ability to raise additional capital, above, we have plans to mobilize resources and achieve levels of production and profits sufficient to recover the carrying value of our oil and gas properties and ventures. However, if one or more of the above factors, or other factors, are different than anticipated, these plans may not be realized, and we may not recover the carrying value of our oil and gas properties and ventures.

Working Capital

At December 31, 2006, our current assets of $24,329,000 exceeded our current liabilities of $12,701,000 million resulting in a working capital surplus of $11,628,000. This compares to a working capital surplus of $14,808,000 as of December 31, 2005. Current liabilities as of December 31, 2006 consisted of trade payables of $4,460,000, deferred revenue of $485,000, accrued liabilities of $7,388,000 and liabilities to be disposed of $369,000.

Capital Expenditures

Capital expenditures in cash in 2006, 2005 and 2004 were $35,278,000, $33,451,000 and $11,190,000, respectively. The table below sets forth the components of these capital expenditures for the three years ended December 31, 2006 2005 and 2004.

		December 31,	
Expenditure category:	**2006**	**2005**	**2004**
Development	$ 9,300,097	$ 13,839,580	$ 6,588,137
Exploration	22,386,167	15,316,075	1,757,010
Facilities and other	3,591,645	4,294,928	2,845,143
Total	35,277,909	33,450,583	11,190,290

During 2006, 2005 and 2004 capital expenditures were primarily for the development and exploration of existing properties. We currently have a contingent planned minimum capital expenditure budget of $15.0 million subject to financing being available for 2007, of which $5.2 million is allocated to our Georgian development and appraisal projects and $9.8 million is committed to our Kazakhstan projects. During 2007, we plan to participate in the workover of two wells on the Ninotsminda Field, complete the testing of the Manavi appraisal well, M12 and complete the drilling and testing of the Kumisi gas exploration well on the Nazvrevi PSC area. Further drilling at

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Norio will be subject to securing financing for this project which may be by way of a farm-out of part of our interest in the PSA in exchange for the drilling of an appraisal well. We have no material long-term capital commitments and are consequently able to adjust the level of our expenditures as circumstances dictate. Additionally, the level of capital expenditures will vary during future periods depending on the results of our development and appraisal programs, market conditions and other related economic factors. Should the prices of crude oil and natural gas decline from current levels; our cash flows will decrease which may result in a reduction of the capital expenditures budget. If we decrease our capital expenditures budget, we may not be able to offset crude oil and natural gas production volume decreases caused by natural field declines and sales of producing properties.)

Commencing in July 2009 through July 2010 an aggregate of $53 million in indebtedness under the Company s Senior Secured Notes, the Subordinated Notes, the 12% Subordinated Notes and the Tethys Bridge Financing (collectively, the Notes) will come due and be payable. Unless such Notes are converted into shares of common stock in accordance with their respective terms, the Company will be required to repay or refinance such outstanding indebtedness. There can be no assurance at this time that Company will have the resources to repay such Notes or if it will be in a position to refinance such indebtedness. The Notes are secured by all the assets of the Company.

Sources of Capital

The net funds provided by and/or used in each of the operating, investing and financing activities are summarized in the following table and discussed in further detail below:

		December 31,	
	2006	**2005**	**2004**
Net cash used in operating activities	$ **(9,320,209)**	$ (8,871,961)	$ (4,311,695)
Net cash used in investing activities	**(37,178,642)**	(33,696,496)	(9,967,084)
Net cash provided in financing	**43,831,811**	35,888,798	34,771,028
Net cash flows from assets and liabilities held for sale	**579,032**	603,170	652,546
Total	**(2,088,008)**	(6.076,489)	21,144,795

Operating activities for the year ended December 31, 2006 used $9,320,000 of cash. Investing activities used $37,179,000 during 2006. Financing activities provided us $43,832,000 during 2006. These funds will be used primarily to continue to fund and develop our Georgian and Kazakhstan projects. In 2006, cash used in operating activities was used principally for production purposes on the Ninotsminda Fields in Georgia and to fund selling, general and administrative overhead. In 2006, cash used in investing activities was due to capital expenditures principally in Georgia ($21,894,000), capital expenditures in Kazakhstan ($11,322,000) and prepaid expenditures relating to our Georgian and Kazakhstan projects ($1,901,000).

Future Capital Resources

We will have four principal sources of liquidity going forward: (i) cash on hand, (ii) cash from operating activities, (iii) industry participation in our projects, and (iv) sales of producing properties. We may also attempt to raise additional capital through the issuance of additional debt or equity securities in public offerings or through further private placements, however, our ability to secure additional debt financing is restricted under the terms of our Senior Secured Notes, Subordinated Notes, 12% Subordinated Notes and the Tethys Bridge.

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Balance Sheet Changes

All balances represent results from continuing operations, unless disclosed otherwise.

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

Cash and cash equivalents decreased $2,088,000 from $18,541,000 at December 31, 2005 to $16,453,000 at December 31, 2006. The decrease was due to expenditures in the period to primarily fund the cost of development activities at the Ninotsminda Field and the appraisal of our Manavi oil discovery in Georgia, activities in Kazakhstan and net cash used by operating activities partially offset by cash received pursuant to the Subordinated Notes, the 12% Subordinated Notes, the Tethys Bridge, proceeds from the Reg. S Offering and the maturing of deposits previously recorded as restricted cash

Restricted cash decreased to $300,000 at December 31, 2006 from $3,182,000 at December 31, 2005 due to the maturing of deposits securing the issuance of letters of credit as required under the rig rental and drilling contracts we entered into with Saipem, S.p.A.

Accounts receivable increased from $413,000 at December 31, 2005 to $509,000 at December 31, 2006 primarily due to an increase in insurance claim amounts receivable in connection with our Georgian exploration activities.

Crude oil inventory decreased to $453,000 at December 31, 2006 from $886,000 at December 31, 2005 primarily as a result of increased sales from storage in the period.

Prepayments to oil and gas equipment suppliers increased from $4,376,000 at December 31, 2005 to $6,443,000 at December 31, 2006 as a result of timing differences in respect of prepayments for materials and services related to our appraisal activities at the Manavi oil discovery and Kumisi gas discovery and our Kazakhstan pipeline construction activities, an increase in prepaid financing fees and an increase in insurance premiums prepaid. Upon receipt of the materials and services, those amounts will be transferred to capital assets. This increase is included in the statement of cash flows as an investing activity.

Non current accounts receivables of $1,086,000 at December 31, 2006 relate to VAT amounts recoverable from our Kazakhstan operations as an offset against VAT payable on future gas revenues.

Capital assets net, decreased to $110,546,000 at December 31, 2006 from $119,048,000 at December 31, 2005, due to an impairment of $38,400,000 on our Georgian capital assets as a result of the ceiling test application, partially offset by investing in capital assets including oil and gas properties and equipment, principally related to the Ninotsminda Production Sharing Contract and the development of the Kazakhstan project. The impairment was attributable to a downward revision in proved developed oil reserves from the Ninotsminda Field following the 2006 assessment by the Company s independent Petroleum Engineers.

Accounts payable decreased to $4,460,000 at December 31, 2006 from $5,271,000 at December 31, 2005 primarily due to timing differences in respect of payments to suppliers in connection with our appraisal activities at the Manavi oil discovery, our horizontal well development program at the Ninotsminda Field and our Kazakhstan activities.

Loans payable decreased to $0 at December 31, 2006 from $964,000 at December 31, 2005 due to the conversion of the Loan with Detachable Warrants of $1,050,000 on February 14, 2006 by exercising the option forcing conversion of the loan into 1,521,739 shares of our common stock.

Deferred revenue of $485,000 at December 31, 2006 relates to the receipt of a deposit in December 2006 for the sale of oil in Georgia to be delivered in 2007.

Accrued liabilities increased from $6,357,000 as at December 31, 2005 to $7,387,000 at December 31, 2006 due primarily to an increase in accrued professional fees and loan interest at the end of the period. Approximately $4,931,000 relates to the disputed Weatherford invoices referred to in Notes 13 and 15 of these consolidated financial statements.

Long term debt net of discounts increased from $25,000,000 at December 31, 2005 to $40,348,000 due to the issuance of the $13,000,000 in Subordinated Notes in March 2006, the $10,000,000 issue of the 12% Subordinated Notes in June 2006 and the issue of the $5,000,000 Senior Secured Notes by our wholly owned subsidiary, Tethys, in September 2006 which have been reduced by unamortized debt discounts associated with the detachable warrants and beneficial conversion features of the Notes in the amount of $12,652,000. The long-term debt at December 31, 2005 of $25,000,000 relates to the issue of the $25,000,000 in Senior Secured Notes in July 2005.

Provision for future site restoration increased to $655,000 at December 31, 2006 from $253,000 at December 31, 2005 primarily due to increases in the provisions for future site restoration in our Kazakhstan oil and gas properties.

Results of Continuing Operations

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

We recorded operating revenue from continuing operations of $6,527,000 during the year ended December 31, 2006 compared with $5,279,000 for the year ended December 31, 2005. The increase is attributable to a higher price per barrel for oil realized by the Company in 2006 and higher sales volumes of oil achieved from the Ninotsminda Field in 2006. Ninotsminda Oil Company Limited (NOC) sold 120,413 barrels of oil for the year ended December 31, 2006 compared to 118,268 barrels of oil for NOC for the year ended December 31, 2005.

NOC generated $6,527,000 of oil and gas revenue in the year ended December 31, 2006 compared with $5,279,000 for the year ended December 31, 2005 due to a higher average net sales price and higher sales volumes. Its net share of the 178,474 bbls (489 bopd) of gross oil production for sale from the Ninotsminda Field in the period amounted to 116,008 bbls. In the period, 4,405 bbls of oil were sold from storage. For the year ended December 31, 2005, NOC s net share of the 184,952 bbls (507 bopd) of gross oil production was 120,219 barrels.

NOC s entire share of production was sold under international contracts or added to storage. Net sale prices for Ninotsminda oil sold during the year ended December 31, 2006 averaged $53.69 per barrel as compared with an average of $44.78 per barrel during the year ended December 31, 2005. NOC s net share of the 20,094 Mcf of gas delivered was 13,061 Mcf at an average net sale price of $0.66 per Mcf of gas for the year ended December 31, 2006. However, due the uncertainty of collectibility of gas revenues under these contracts, the Company has decided in accordance with its revenue recognition policy, to record gas revenues on a cash basis. Gas revenues recorded for the year ended December 31, 2006 were $61,000. For the year ended December 31, 2005, NOC s net share of the 71,241 Mcf of gas delivered was 46,307 Mcf at an average net sale price of $0.53 per Mcf of gas.

The operating loss from continuing operations for the year ended December 31, 2006 amounted to $53,637,000 compared with an operating loss of $11,744,000 for the year ended December 31, 2005. The increase in operating loss is attributable to increased field operating expenses, increased selling, general and administration costs, increased depreciation, depletion and amortization, an impairment of our oil and gas properties, ventures and other assets, partially offset by increased oil and gas revenue and reduced direct project costs.

Field operating expenses increased to $1,703,000 for the year ended December 31, 2006 as compared to $1,110,000 for the year ended December 31, 2005. The increase is primarily a result of increased oil processing fees in the period and costs attached to oil sales from storage in the period.

Direct project costs decreased to $812,000 for the year ended December 31, 2006, from $1,084,000 for the year ended December 31, 2005 primarily due to reduced costs directly associated with non operating activity at the Ninotsminda Field.

Selling, general and administrative costs increased to $14,817,000 for the year ended December 31, 2006 from $11,554,000 for the year ended December 31, 2005. The increase is primarily as a result of the first full year of consolidating the activities of our Kazakhstan related subsidiaries, professional fees incurred in relation to the proposed Tethys Spin Out and a general increase in corporate activity, partially offset by reduced non cash stock compensation expense.

The increase in depreciation, depletion and amortization expense to $3,831,000 for the year ended December 31, 2006 from $3,276,000 for the year ended December 31, 2005 is primarily attributable to a downward revision in proved developed oil reserves from the Ninotsminda Field following the 2006 assessment by the Company s independent Petroleum Engineers.

The impairment of $39,000,000 of oil and gas properties, ventures and other assets for the year ended December 31, 2006 was primarily attributable to a downward revision in proved developed oil reserves from the Ninotsminda Field following the 2006 assessment by the Company s independent Petroleum Engineers and also an impairment to the 3 megawatt generator held for sale.

The increase in other expense to $7,577,000 for the year ended December 31, 2006, from $1,194,000 for the year ended December 31, 2005 is primarily a result of lower interest income received due to having lower amounts of surplus cash available to place on term deposit, higher loan interest payable and amortised debt discount and expense, higher foreign exchange gains and fees incurred in respect of a private placement in 2006.

The loss from continuing operations of $61,214,000 or $0.27 per share for the year ended December 31, 2006 compares to a net loss from continuing operations of $12,938,000 or $0.06 per share for the year ended December 31, 2005. The weighted average number of common shares outstanding was higher during the year ended December 31, 2006 than during the year ended December 31, 2005, principally due to the issue of shares in respect of the forced conversion of a convertible Loan with Detachable Warrants in 2006, the exercise of share options in 2006 and a private placement in 2006.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

We recorded operating revenue from continuing operations of $5,279,000 during the year ended December 31, 2005 compared with $7,833,000 for the year ended December 31, 2004. The decrease is attributable to lower oil and gas revenues being recorded in the year ended December 31, 2005 due to lower production levels relating to a delay in the UBCTD program on the Ninotsminda Field. NOC sold 118,268 barrels of oil for the year ended December 31, 2005 compared to 313,030 barrels of oil for the year ended December 31, 2004.

NOC generated $5,279,000 of oil and gas revenue in the year ended December 31, 2005 compared with $7,833,000 for the year ended December 31, 2004 primarily due to lower production achieved in the year ended December 31, 2005 compared to the year ended December 31, 2004 offset partially by a higher average net sales price achieved in the year ended December 31, 2005 compared to the year ended December 31, 2004. Its net share of the 184,952 bbls (507 bopd) of gross oil production for sale from the Ninotsminda Field in the period amounted to 120,219 bbls. As at December 31, 2005, 10,601 bbls of oil remained in storage. For the year ended December 31, 2004, NOC s net share of the 370,176 bbls (1,011 bopd) of gross oil production for sale from the Ninotsminda Field in the period amounted to 242,131 bbls.

NOC s share of production was either sold locally in Georgia under both national and international contracts or added to storage. Net sale prices for Ninotsminda oil sold during 2005 averaged $44.78 per barrel as compared with an average of $24.83 per barrel in 2004. Its net share of the 71,241 Mcf of gas delivered was 46,307 Mcf at an average net sale price of $0.53 per Mcf of gas. For the year ended December 31, 2004, NOC s net share of the 65,066 Mcf of gas delivered was 42,293 Mcf at an average net sale price of $1.41 per Mcf of gas.

The operating loss from continuing operations for the year ended December 31, 2005 amounted to $11,744,000 compared with an operating loss of $4,036,000 for the year ended December 31, 2004. The increase in operating loss is attributable to increased selling, general and administration costs, increased non cash stock compensation expense, increased depreciation, depletion and amortization, reduced oil and gas revenue and a gain generated from the disposal of GAOR in the year ended December 31, 2004, partially offset by reduced field operating expenses and direct project costs in the period.

Field operating expenses decreased to $1,110,000 for the year ended December 31, 2005 as compared to $1,829,000 for the year ended December 31, 2004. The decrease is primarily a result of decrease in production at the Ninotsminda Field as a result of the Company continuing to focus on the long-term development of its producing assets in Georgia through the preparation of wells for the Under-Balanced Coiled Tubing Drilling (UBCTD) technology program together with a delay in implementing the program itself due to mechanical difficulties with the equipment. The preparation work for the UBCTD program necessitated the shut in of producing wells during the period thus resulting in a lower average production for the period.

Direct project costs decreased to $1,084,000 for the year ended December 31, 2005, from $1,098,000 for the year ended December 31, 2004 due to a decrease in costs directly associated with non operating activity at the Ninotsminda Field.

Selling, general and administrative costs increased to $11,554,000 for the year ended December 31, 2005 from $7,492,000 for the year ended December 31, 2004. The increase is a result of additional costs incurred in respect of compliance with Section 404 of the Sarbanes-Oxley Act of 2002, increased audit fees, legal fees, higher insurance premiums and a general increase in corporate activity. Included in selling, general and administrative costs is non cash stock compensation expense, which increased to $2,375,000 for the year ended December 31, 2005 from $1,395,000 for the year ended December 31, 2004 due to share options issued expensed during the period. The Company, effective January 1, 2003, adopted in August 2003, the fair value recognition provisions of SFAS No. 123, Accounting for Stock-Based Compensation, prospectively to all employee awards granted, modified, or settled after December 31, 2002.

The increase in depreciation, depletion and amortization expense to $3,276,000 for the year ended December 31, 2005 from $2,881,000 for the year ended December 31, 2004 is attributable to additions to the full cost pool during 2005, partially offset by lower production in 2005 compared to 2004.

We impaired our Caspian Sea project to zero during the year ended December 31, 2004 with a write down of $65,000 of oil and gas properties and a $75,000 write down of our investment. Impairment of other assets of $35,000 during the year ended December 31, 2004 relates to repairs to the held for sale generator which are not recoverable.

The gain on disposal of subsidiaries of $1,606,000 recorded for the year ended December 31, 2004 reflects gains from the disposals of CSOP and of our interest in GAOR.

The decrease in other expense to $1,194,000 for the year ended December 31, 2005 from $2,226,000 for the year ended December 31, 2004 is primarily a result of favourable exchange rate movements in 2005, the realization of the advanced proceeds on the sale of the generator that was abandoned, partially offset by higher interest expense charges due to increased borrowing and increased levels of bad debts.

The decrease in equity loss from investments for the year ended December 31, 2005 to $155,000 from $205,000 for the year ended December 31, 2004 is a result of acquiring 100% ownership in Tethys Petroleum Limited in June 2005 and therefore only equity accounting for our share of the loss for the first six months of 2005.

The loss from continuing operations of $12,938,000 or $0.06 per share for the year ended December 31, 2005 compares to a net loss from continuing operations of $6,262,000 or $0.04 per share for the year ended December 31, 2004. The weighted average number of common shares outstanding was higher during the year ended December 31, 2005 than during the year ended December 31, 2004 principally due to the issue of shares in respect of the Samgori purchase in April 2004, the issue of shares in respect of a global offering in September 2004, the issue of shares in respect of the Norio minority interest buyout in September 2004, the issue of shares under the terms of the SEDA in 2005 to repay the Cornell Capital promissory notes and in connection with additional takedowns under the SEDA, the exercise of share options in 2005 and the issue of shares in respect of the Tethys Petroleum Limited buyout.

Results of Discontinued Operations

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

On February 17, 2006 we issued a press release announcing that our subsidiary, CSL, was not proceeding with further investment in the Samgori (Block XI ^{B}) Production Sharing Contract (Samgori PSC) in Georgia and associated farm-in which became effective in April 2004, and accordingly we terminated our 50% interest in the Samgori PSC with effect from February 16, 2006.

The net income from discontinued operations, net of taxes for the year ended December 31, 2006 of $673,000 increased from $603,000 for the year ended December 31, 2005 due to the activities of CSL. On February 16, 2006 we withdrew from the Samgori PSC.

CSL generated $1,003,000 of oil and gas revenue in the year ended December 31, 2006 compared with $2,303,000 for the year ended December 31, 2005 primarily due to a higher average net sales price achieved in the year ended December 31, 2006 offset by lower sales volumes. Its net share of the 10,226 bbls (218 bopd) of gross oil production for sale from the Samgori Field in the period up to February 16, 2006, the date of withdrawal, amounted to 3,835 bbls. In the period, 5,141 bbls of oil were added to storage. For the year ended December 31, 2005, CSL s net share of the 166,298 bbls (456 bopd) of gross oil production was 62,362 bbls

CSL s entire share of production was either sold locally in Georgia under international contracts or added to storage. Net sale prices for CSL oil sold during the period up to February 16, 2006, the date of withdrawal, averaged $59.57 per barrel as compared with an average of $46.12 per barrel for the year ended December 31, 2005.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

On February 17, 2006 we issued a press release announcing that our subsidiary, CSL, was not proceeding with further investment in the Samgori (Block XI ^{B}) Production Sharing Contract (Samgori PSC) in Georgia and associated farm-in which became effective in April 2004, and accordingly we terminated our 50% interest in the Samgori PSC with effect from February 16, 2006.

The net income from discontinued operations, net of taxes for the year ended December 31, 2005 of $603,000 decreased from $1,504,000 for the year ended December 31, 2004. Discontinued operations for the year ended December 31, 2005 relate to the activities of CSL. On February 16, 2006 we withdrew from the Samgori PSC. The net income from discontinued operations, net of taxes for the year ended December 31, 2004 amounted to $1,504,000. Discontinued operations for the year ended December 31, 2004 related to the activities of CSL, income relating to the refinery resulting from the disposal of the refinery in the period, partially offset by the activities of CanArgo Standard Oil Products Limited (CSOP), mainly due to interest on additional bank loans drawn by CSOP in Tbilisi, Georgia.

CSL generated $2,303,000 of oil and gas revenue in the year ended December 31, 2005 compared with $1,742,000 from the purchase date to December 31, 2004 due to a higher average net sales price achieved in the year ended December 31, 2005 and higher sales volumes. Its net share of the 166,298 bbls (456 bopd) of gross oil production for sale from the Samgori Field for the year ended December 31, 2005 amounted to 62,362 bbls. From the purchase date to December 31, 2004, CSL s net share of the 152,169 bbls (2,832 bopd) of gross oil production was 57,063 bbls. As at December 31, 2004, 5,964 bbls of oil remained in storage.

CSL s entire share of production was either sold locally in Georgia under international contracts or added to storage. Net sale prices for CSL oil sold for the year ended December 31, 2005, averaged $46.12 per barrel as compared with an average of $33.96 per barrel from purchase date to December 31, 2004.

Contractual Obligations and Commercial Terms

Our principal business and assets are derived from production sharing contracts in Georgia. The legislative and procedural regimes governing production sharing contracts and mineral use licenses in Georgia have undergone a series of changes in recent years resulting in certain legal uncertainties.

Our production sharing contracts and mineral use licenses, entered into prior to the introduction in 1999 of a new Petroleum Law governing such agreements have not, as yet, been amended to reflect or ensure compliance with current legislation. As a result, despite references in the current legislation grandfathering the terms and conditions of our production sharing contracts, conflicts between the interpretation of our production sharing contracts and mineral use licenses and current legislation could arise. Such conflicts, if they arose, could cause an adverse effect on our rights under the production sharing contracts. However, the Norio PSA and the Tbilisi PSC were concluded after enactment of the Petroleum Law, and under the terms and conditions of this legislation.

To confirm that the Ninotsminda PSC and the mineral usage license issued prior to the introduction in 1999 of the Petroleum Law were validly issued, in connection with its preparation of the Convertible Loan Agreement with us, the International Finance Corporation, an affiliate of the World Bank received in November 1998 confirmation from the State of Georgia, that among other things:

The State of Georgia recognizes and confirms the validity and enforceability of the production sharing contract and the license and all undertakings the State has covenanted with NOC thereunder;

the license was duly authorized and executed by the State at the time of its issuance and remained in full force and effect throughout its term; and

the license constitutes a valid and duly authorized grant by the State, being and remaining in full force and effect as of the signing of this confirmation and the benefits of the license fully extend to NOC by virtue of its interest in the license holder and the contractual rights under the production sharing contract.

Despite this confirmation and the grandfathering of the terms of existing production sharing contracts in the Petroleum Law, subsequent legislative or other governmental changes could conflict with, challenge our rights or otherwise change current operations under the production sharing contract. No challenge has been made to date.

In 2002, the Participation Agreement for the three well exploration program on the Ninotsminda / Manavi area with AES was terminated without AES earning any rights to any of the Ninotsminda / Manavi area reservoirs. The Company therefore has no present obligations in respect of AES. However, under a separate

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Letter of Agreement, if gas from the sub Middle Eocene is discovered and produced from the exploration area covered by the Participation Agreement, AES with be entitled to recover at the rate of 15% of future gas sales from the sub Middle Eocene, net of operating costs, approximately $7,500,000, representing their prior funding under the Participation Agreement.

Under the Production Sharing Contract for Blocks XI^G and XI^H (the Tbilisi PSC) our subsidiary CanArgo Norio Limited had a commitment to acquire additional seismic data within three years of the effective date of the contract which is September 29, 2003. The State Agency for Oil & Gas Regulation in Georgia (the Agency) has consented to an extension to the period within which the data should be acquired and we are working with the Agency to amend the Tbilisi PSC accordingly. The total commitment over the remaining period is $350,000.

We have contingent obligations and may incur additional obligations, absolute or contingent, with respect to the acquisition and development of oil and gas properties and ventures in which we have interests that require or may require us to expend funds and to issue shares of our common stock.

Upon completion of the acquisition of an interest in the Samgori PSC we had a contractual obligation to issue four million shares of CanArgo common stock to Europa Oil Services Limited (Europa), an unaffiliated company in connection with a consultancy agreement with Europa in relation to this acquisition. On April 16, 2004 Europa was issued with four million restricted shares of CanArgo common stock in an arms length transaction. A further 12 million shares of CanArgo common stock are issuable upon certain production targets being met from future developments under the Samgori PSC. As we have withdrawn from the Samgori PSC effective February 16, 2006, we have no continuing obligation to issue further shares of CanArgo common stock to Europa. On March 14, 2006, we signed an agreement with Europa formally terminating the consultancy agreement.

At December 31, 2006, we had a contingent obligation to issue a maximum of 187,500 shares of common stock to Fielden Management Services PTY, Ltd (a third party management services company) upon satisfaction of conditions relating to the achievement of specified Stynawske Field project performance standards, an oil field in Ukraine in which we had a previous interest.

In September 2004, a blow-out occurred at the N100 well on the Ninotsminda Field. Our insurers will cover 80% of the costs associated with the blow out up to a maximum cover of $2,500,000. We received $800,000 from our insurers in the second quarter of 2005 and $560,000 in the third quarter of 2006, in respect of costs incurred to date.

The following table sets forth information concerning the amounts of payments due under specified contractual obligations for periods of less than one year, one to three years, three to five years and more than five years as at December 31, 2006:

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	Due in less than 1 year	Due in 1 to 3 years	Due in 3 to 5 years	Due in more than 5 years
Contractual Obligations				
Operating lease obligations	$ 844,588	955,231	180,066	45,017
Long term debt		53,000,000		
Long term debt interest	7,000,000	11,506,164		
Other long-term liabilities (1)				655,867
	$7,844,588	65,461,395	180,066	700,884

(1) Other long-tem liabilities represent costs provided for future site restoration.

(2) CanArgo has no contractual obligations in respect of capital leases or purchase obligations.

Related Party Transactions

A company owned by key employees of Georgian British Oil Company Ninotsminda until February 2005 and the same employees of CanArgo Georgia Limited from February 1, 2005 provided certain equipment, office and storage space to Georgian British Oil Company Ninotsminda until February 2005 and to CanArgo Georgia Limited from February 1, 2005. Total rental payments for this equipment, office and storage space in 2006 were $216,810 ($281,024 and $107,946 in 2005 and 2004 respectively). In 2004, the same company provided additional services to Georgian British Oil Company Ninotsminda in accordance with a farm-in agreement in respect of the Manavi well for the value of $450,000. No additional services were provided in 2006 or 2005.

Dr. David Robson, Chief Executive Officer, provides all of his services to CanArgo through Vazon Energy Limited, a corporation organized under the laws of the Bailiwick of Guernsey, of which he is the sole owner and Managing Director. In addition a management services agreement exists between CanArgo and Vazon Energy whereby the services of Dr. Robson and Mrs. Landles (Corporate Secretary and Executive Vice President) and for part of the year Mr. Battey (former Chief Financial Officer), amongst others, are provided to CanArgo.

In December 2003, we announced details of the conditional acquisition of certain oil and gas interests in Kazakhstan which had previously been owned by the UK public company, Atlantic Caspian Resources plc (ACR). This was to be achieved through a newly established company, Tethys Petroleum Investments Limited (now renamed Tethys Petroleum Limited (TPL)) on certain conditions being satisfied. These interests were represented as including a 70% interest in BN Munai LLP (BNM), a Kazakh limited liability partnership, which was represented as holding certain exploration and production interests in Kazakhstan including the Akkulka exploration licence and contract and Kyzyloi production licence. Immediately prior to the agreement between TPL and ACR, and as part of that transaction, we entered into an agreement allocating a 45% interest in TPL to Provincial Securities Limited (an investment company to which Mr. Russell Hammond, one of our non-executive directors, is an Investment Advisor) in consideration for future services of providing advice, help and assistance concerning funding the development of TPL. This transaction resulted in us holding a 45% non-controlling interest in TPL with the remaining interest holder in TPL being ACR with a 10% interest.

Mr. Russell Hammond, a non-executive director of CanArgo, is also an Investment Advisor to Provincial Securities Limited who became a minority shareholder in the Norio PSA through a farm-in agreement to the Norio MK72 well. On September 4, 2003 we concluded a deal to purchase Provincial Securities Limited s minority interest in CanArgo Norio Limited by a share swap for shares in CanArgo. Provincial Securities Limited received 2,234,719 shares of CanArgo common stock in relation to the transaction. Provincial Securities Limited also had an interest in Tethys Petroleum Limited which was sold in June 2005 to us by a share exchange for shares in CanArgo. Provincial Securities Limited received 5,500,000 shares of CanArgo common stock in relation to the transaction. Mr Hammond did not receive any compensation in connection with these transactions and disclaims any beneficial ownership of Provincial Securities Limited or any of the Company s common stock owned by Provincial Securities Limited.

Transactions with affiliates or other related parties including management of affiliates are to be undertaken on the same basis as third party arms-length transactions. Transactions with affiliates are reviewed and voted on solely by non-interested directors.

Critical Accounting Policies

Natural Gas and Oil Properties

We utilize the full cost method of accounting for costs related to our natural gas and oil properties. We review the carrying value of our natural gas and oil properties under the full cost accounting rules of the SEC. Under these rules, all such costs excluding significant acquisition, exploration and development costs related to unproved properties, are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test, however, which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved gas and oil reserves discounted at

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10 percent plus the lower of cost or market value of unproved properties. If the net capitalized costs of natural gas and oil properties exceed the ceiling, we will record a ceiling test write-down to the extent of such excess. A ceiling test write-down is a non-cash charge to earnings. If required, it reduces earnings and impacts shareholders equity in the period of occurrence and results in lower depreciation, depletion and amortization expense in future periods. The write-down may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling.

The risk that we will be required to write-down the carrying value of our natural gas and oil properties increases when natural gas and oil prices are depressed or if there are substantial downward revisions in estimated proved reserves. Application of these rules during periods of relatively low natural gas or oil prices due to seasonality or other reasons, even if temporary, increases the probability of a ceiling test write-down. Based on natural gas and oil prices in effect on December 31, 2005, the unamortized cost of our natural gas and oil properties did not exceed the ceiling of proved natural gas and oil reserves. Natural gas pricing has historically been unpredictable and any significant declines could result in a ceiling test write-down in subsequent quarterly or annual reporting periods.

Natural gas and oil reserves used in the full cost method of accounting cannot be measured exactly. Our estimate of natural gas and oil reserves requires extensive judgments of reservoir engineering data and is generally less precise than other estimates made in connection with financial disclosures. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. The uncertainties inherent in the disclosure are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves. We engage the services of an independent petroleum consulting firm to calculate reserves.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Management believes that it is reasonably possible the following material estimates affecting the financial statements could significantly change in the coming year: (1) estimates of proved oil and gas reserves, (2) estimates as to the expected future cash flow from proved oil and gas properties, and (3) estimates of future dismantlement and restoration costs.

Concentration of Credit Risk

Although our cash and temporary investments and accounts receivable are exposed to potential credit loss, we do not believe such risk to be significant. Even though a substantial amount of funds were in accounts at financial institutions which were not covered under bank guarantees, management does not believe that maintaining balances in excess of bank guarantees resulted in a significant risk to the Company.

Foreign Operations

Our future operations and earnings will depend upon the results of our operations in Georgia and Kazakhstan. There can be no assurance that we will be able to successfully conduct such operations, and a failure to do so would have a material adverse effect on the our financial position, results of operations and cash flows. Also, the success of our operations will be subject to numerous contingencies, some of which are beyond management control. These contingencies include general and regional economic conditions, prices for crude oil and natural gas, competition and changes in regulation. Since we are dependent on international operations, specifically those in Georgia and Kazakhstan, we will be subject to various additional political, economic and other uncertainties. Among other risks, our operations may be subject to the risks and restrictions on transfer of funds, import and export duties, quotas and embargoes, domestic and international customs and tariffs, and changing taxation policies, foreign exchange restrictions, political conditions and regulations.

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Recently Issued Pronouncements

In July 2006, the FASB issued Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109, which seeks to reduce the diversity in practice associated with the accounting and reporting for uncertainty in income tax positions. This Interpretation prescribes a comprehensive model for the financial statement recognition, measurement, presentation and disclosure of uncertain tax positions taken or expected to be taken in income tax returns. FIN 48 is effective for fiscal years beginning after December 15, 2006 and the Company will adopt the new requirements in its fiscal first quarter of 2007. The Company does not expect the adoption of this statement in fiscal year 2007 to have a material impact on the Company s financial position or results of operations.

In September 2006, the FASB issued Statement of Financial Accounting Standards (SFAS) 157, Fair Value Measurements (SFAS 157) , which provides guidance on measuring the fair value of assets and liabilities. SFAS 157 will apply to other accounting pronouncements that require or permit assets or liabilities to be measured at fair value but does not expand the use of fair value to any new circumstances. This standard will also require additional disclosures in both annual and quarterly reports. SFAS 157 will be effective for financial statements issued for fiscal years beginning after November 15, 2007. The Company is currently determining the effect, if any, the adoption of SFAS 157 will have on its financial statements.

In September 2006, the SEC staff issued Staff Accounting Bulletin No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements (SAB 108). The intent of SAB 108 is to reduce diversity in practice for the method companies use to quantify financial statement misstatements, including the effect of prior year uncorrected errors. SAB 108 establishes an approach that requires quantification of financial statement errors using both an income statement and a cumulative balance sheet approach. SAB 108 is effective for fiscal years beginning after November 15, 2006, and the Company will adopt the new requirements in fiscal 2008. The adoption of SAB 108 is not currently expected to have a significant impact on the Company s consolidated financial statements.

Forward-Looking Statements

The forward-looking statements contained in this Item 7 and elsewhere in this Annual Report on Form 10-K are subject to various risks, uncertainties and other factors that could cause actual results to differ materially from the results anticipated in such forward-looking statements. Included among the important risks, uncertainties and other factors are those hereinafter discussed.

Few of the forward-looking statements in this Annual Report deal with matters that are within our unilateral control. Joint venture, acquisition, financing and other agreements and arrangements must be negotiated with independent third parties and, in some cases, must be approved by governmental agencies. These third parties generally have objectives and interests that may not coincide with ours and may conflict with our interests. Unless we are able to compromise these conflicting objectives and interests in a mutually acceptable manner, agreements and arrangements with these third parties will not be consummated.

Operating entities in various foreign jurisdictions must be registered by governmental agencies, and production licenses for development of oil and gas fields in various foreign jurisdictions must be granted by governmental agencies. These governmental agencies generally have broad discretion in determining whether to take or approve various actions and matters. In addition, the policies and practices of governmental agencies may be affected or altered by political, economic and other events occurring either within their own countries or in a broader international context. Finally, due to the developing nature of the legal regimes in many former Soviet Union countries where we operate, our contractual rights and remedies may be subject to certain legal uncertainties.

We do not have a majority of the equity in the entity that is the licensed developer of some projects, that we may pursue in the former Soviet Union, even though we may be the designated operator of the oil or gas field. In these circumstances, the concurrence of co-venturers may be required for various actions. Other parties influencing the timing of events may have priorities that differ from ours, even if they generally share our objectives. As a result of all of the foregoing, among other matters, any forward-looking statements regarding the occurrence and timing of future events may well anticipate results that will not be realized. Demands by or expectations of governments, co-venturers, customers and others may affect our strategy regarding the various projects. Failure to meet such demands or expectations could adversely affect our participation in such projects or our ability to obtain or maintain necessary licenses and other approvals.

Our ability to finance all of its present oil and gas projects and other ventures according to present plans is dependent upon obtaining additional funding. An inability to obtain financing could require us to scale back or abandon part of all of our project development, capital expenditure, production and other plans. The availability of equity or debt financing to us or to the entities that are developing projects in which we have interests is affected by many factors, including:

- world economic conditions;

- the state international relations;

- the stability and policies of various governments located in areas in which we currently operate or intend to operate;

- fluctuations in the price of oil and gas, the general outlook for the oil and gas industry and competition for available funds; and

- an evaluation of us and specific projects in which we have an interest.

Rising interest rates might affect the feasibility of debt financing that is offered. Potential investors and lenders will be influenced by their evaluations of us and our projects and comparisons with alternative investment opportunities.

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Our principal exposure to market risk is due to changes in oil and gas prices and currency fluctuations. As indicated elsewhere in this Report, as a producer of oil and gas we are exposed to changes in oil and gas prices as well as changes in supply and demand which could affect our revenues. We do not engage in any commodity hedging activities. Due to the ready market for our production in Georgia, we do not believe that any current exposures from this risk will materially affect our financial position at this time, but there can be no assurance that changes in such market will not affect us adversely in the future.

Also as indicated elsewhere in this Report, because all of our operations are being conducted in the former Soviet Union, we are potentially exposed to the market risk of fluctuations in the relative values of the currencies in areas in which we operate. At present we do not engage in any currency hedging operations since, to the extent we receive payments for our production and marketing activities in local currencies, we are utilizing such currencies to pay for our local operations. In addition, our contracts to sell our production from the Ninotsminda Field in Georgia is denominated in US dollars with all export contracts providing for payment in dollars, although we may not always be able to continue to demand payment in U.S. dollars. Production from the Kyzyloi Field in Kazakhstan will be delivered under a natural gas supply contract concluded between BNM and Gaz Impex in January 2006 with payment in US dollars.

We had no material interest in investments subject to market risk during the period covered by this Report.

Because the majority of all revenue to us is from the sale of production from the Ninotsminda Field a change in the price of oil or a change in the production rates could have a substantial effect on this revenue and therefore profits.

Assuming the same production in 2007 as 2006 but decreasing the net oil price we receive from sales by $5.00 and $10.00 respectively would change the total annual revenue from oil sales as follows. The total annual revenue from oil sales for 2006 based on an average net oil price received of $53.69 was $6,465,239. If the average net oil price received was $5.00 less at $48.69 then the total annual revenue from oil sales would be reduced by $602,065 to $5,863,174. If the average net oil price received was reduced by $10 per barrel then the total annual revenue from oil sales realised would be reduced by $1,204,130 to $5,261,109, assuming all other factors are constant.

Assuming constant oil prices a reduction in annual production by 20% and 50% would have the following effect on total annual revenues. In 2006 total oil sales were 120,413 bbls of oil producing revenue of $6,465,239. If this was reduced by 20% then the annual revenue from oil sales would be reduced to $5,172,191. If the total annual oil sales were reduced by 50% or 60,206 bbls then the total annual revenue from oil sales would be $3,232,620, assuming all other factors are constant.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The Financial Statements required to be filed in this Report begin at Page F-1 of this Report.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. CONTROLS AND PROCEDURES.

Management s Responsibility for Financial Statements

Our management is responsible for the integrity and objectivity of all information presented in this Annual Report. The consolidated financial statements were prepared in conformity with accounting principles generally accepted in the United States of America and include amounts based on management s best estimates and judgments. Management believes the consolidated financial statements fairly reflect the form and substance of transactions and that the financial statements fairly represent the Company s financial position and results of operations. The Audit Committee of the Board of Directors, which is composed solely of independent directors, meets regularly with the independent auditors, L J Soldinger Associates LLC and representatives of management to review accounting, financial reporting, internal control and audit matters, as well as the nature and extent of the audit effort. The Audit Committee is responsible for the engagement of the independent auditors. The independent auditors have free access to the Audit Committee.

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our chief executive officer and chief financial officer, we evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2006. Based on that evaluation, our chief executive officer and chief financial officer have concluded that our disclosure controls and procedures are not effective to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized and reported within the time periods specified in the Commission s rules and forms and to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure.

Management s Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting, is defined in the rules promulgated under the Exchange Act as a process designed by, or under the supervision of, the Company s principal executive and principal financial officers and effected by the Company s Board, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting procedures (GAAP) and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the Company;

- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with US GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and Directors of the Company; and

- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company s assets that could have a material effect on the financial statements.

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A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, control may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

Under the supervision and with the participation of our management, including our principal executive, financial and accounting officers, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2006 based on the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Our assessment of the effectiveness of internal control over financial reporting as of December 31, 2006, has been audited by L J Soldinger Associates, LLC, an independent registered public accounting firm, as stated in their report as set forth at the end of this section.

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of our annual or interim financial statements would not be prevented or detected. As of December 31, 2006, we have concluded that our internal control over financial reporting was ineffective as of December 31, 2006 and that we have material weaknesses in each of the following areas:

1. Disclosure Controls

The Company s disclosure controls and procedures were not effective to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Commission s rules and forms and to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including chief executive officer and chief financial officer, as appropriate to allow timely decisions. Inadequate controls include the lack of procedures used for identifying, determining, and calculating required disclosures and other supplementary information requirements.

2. Information Technology

The Company did not adequately implement certain controls over information technology, including certain spreadsheets, used in its core business and financial reporting. These areas included logical access security controls to financial applications, segregation of duties and backup and recovery procedures. The Company s controls over the completeness, accuracy, validity, restricted access, and the review of certain spreadsheets used in the period-end financial statement preparation and reporting process was not designed appropriately. This material weakness affects the Company s ability to prevent improper access and changes to its accounting records and misstatements in the financial statements could occur and not be prevented or detected by the Company's controls in a timely manner.

As a result, misappropriation of assets and misstatements in the financial statements could occur and not be prevented or detected by the Company s controls in a timely manner. In light of the review, Management, in consultation with the Audit Committee, is reviewing the most cost effective way to address the issues raised.

CEO and CFO Certifications The Certifications of our CEO and CFO which are attached as Exhibits 31(1) and 31(2) to this Report include information about our disclosure controls and procedures and internal control over financial reporting. These Certifications should be read in conjunction with the information contained in this Item 9A for a more complete understanding of the matters covered by the Certifications.

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Changes in Internal Control over Financial Reporting

There were changes in our internal control in the fourth quarter in the following areas:

1. Financial Statement Close Process

The Company introduced controls in the financial reporting close process as follows:

- Visits by head office accounting staff to Georgia and Kazakhstan to review the trial balances and financial statements prepared at location level for inclusion in the group consolidation; and

- Preparation and review of account reconciliations at all locations, particularly in Georgia and Kazakhstan, are now performed; and

- Review and approval of various schedules and reconciliations, including the transfer of amounts from subsidiary trial balances to consolidating spreadsheets prepared to support the financial close and disclosure processes; and

- Employment of an additional person in the head office accounting department has increased the segregation of duties levels.

As a result of these and other measures we have taken to date, we believe the material weaknesses related to the financial statement close process reported in our Annual Report on Form 10-K for the year ended December 31, 2005, have been remediated.

2. Production

Our Annual Report on Form 10-K for the year ended December 31, 2005, reported deficiencies in our internal controls and procedures relating to the recording of production which did not allow assurance that revenues and costs were recognized in accordance with generally accepted accounting principles. We believe that these deficiencies related to the recording of oil production from the Samgori Field in Georgia, as we did not have any interest in the PSC operating company and the lack of adequate metering systems to measure oil produced from the Ninotsminda Field in Georgia. We withdrew from the Samgori project in February 2006 and introduced new metering systems in our Ninotsminda Field in the fourth quarter of 2006. We now believe we now have no material weakness relating to the recording of oil and gas production in Georgia.

3. Inventory Management

Our Annual Report on Form 10-K for the year ended December 31, 2005, reported that we did not maintain a control environment that fully emphasized the establishment of, adherence to, or adequate communication regarding appropriate internal control for the management of its inventory, including the lack of documented procedures to update and review the material master file and valuation table or compare the cost of inventory to net realizable value. We stated that these weaknesses increased the likelihood of potential material errors in our financial reporting. We now include the cost of materials inventory in our ceiling test calculation, which tests the cost of oil and gas properties for impairment. Deficiencies remain in our inventory management process but we believe that these deficiencies do not now constitute a material weakness in our financial reporting.

4. Entity Level Controls

Our Annual Report on Form 10-K for the year ended December 31, 2005, reported that as evidenced by the material weaknesses described above, entity-level controls related to the control environment, risk assessment, monitoring function and dissemination of information and communication activities did not operate effectively. This included a lack of adequate mechanisms for anticipating and identifying financial reporting risks and for reacting to changes in the operating environment that could have a potential effect on financial reporting. As a result of the remediations of the material weakness identified above, particularly those relating to the financial statement close process, and other measures such as the attendance of key accounting personnel at US GAAP and other relevant courses and improved communication between the head office and the subsidiary accounting departments, management now believe that entity-level controls are operating effectively.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and
Stockholders of CanArgo Energy Corporation

We have audited management s assessment, included in the accompanying Management s Report on Internal Control over Financial Reporting, that CanArgo Energy Corporation did not maintain effective internal control over financial reporting as of 31 December 2006, because of the effect of the Material Weaknesses Identified in Management s Assessment, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organization of the Treadway Commission (COSO). CanArgo Energy Corporation s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. The following material weaknesses have been identified and included in management s assessment.

Information Technology

The Company did not adequately implement certain controls over information technology, including certain spreadsheets, used in its core business and financial reporting. These areas included logical access security controls to financial applications, segregation of duties and backup and recovery procedures. The Company s controls over the completeness, accuracy, validity, restricted access, and the review of certain spreadsheets used in the period-end financial statement preparation and reporting process was not designed appropriately. This material weakness affects the Company s ability to prevent improper access and changes to its accounting records and misstatements in the financial statements could occur and not be prevented or detected by the Company's controls in a timely manner.

Disclosure

The Company s disclosure controls and procedures were not effective in providing reasonable assurance that information required to be disclosed in reports filed or submitted under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported, within the time periods specified in the SEC s rules and forms and to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Securities Exchange Act of 1934 is accumulated and communicated to management, including the chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure. Inadequate controls include the lack of procedures used for identifying, determining and calculating required disclosures and other supplementary information requirements.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2006 consolidated financial statements of CanArgo Energy Corporation and our report dated 10 March 2007 expressed an unqualified opinion.

These material weaknesses were considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2006 financial statements, and this report does not affect our report dated 10 March 2007 on those financial statements.

In our opinion, management s assessment that CanArgo Energy Corporation did not maintain effective internal control over financial reporting as of 31 December 2006, is fairly stated, in all material respects, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, because of the effect of the material weaknesses described above on the achievement of the objectives of the control criteria, CanArgo Energy Corporation has not maintained effective internal control over financial reporting as of 31 December 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

L J Soldinger Associates LLC
Deer Park, Illinois USA
10 March 2007

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ITEM 9B. OTHER INFORMATION

On March 14, 2006, we entered into an agreement (Termination Agreement) with Europa Oil Services Limited (Europa), an unaffiliated company, formally terminating the consultancy agreement between CanArgo and Europa dated January 8, 2004. Under the terms of the consultancy agreement, CanArgo had an outstanding obligation to issue up to 12 million shares of CanArgo common stock to Europa upon certain production targets being met from future developments under the Samgori PSC. With effect from February 16, 2006, we have withdrawn from the Samgori PSC. Pursuant to the terms of the Termination Agreement the parties accordingly agreed that the consultancy agreement had terminated with effect from February 16, 2006. CanArgo has not incurred any material early termination penalties as a result of the termination of the consultancy agreement.

Agreement has now also been reached whereby, subject to any required Kazakh regulatory approvals Tethys, through its wholly owned subsidiary Tethys Kazakhstan Limited (TKL) will acquire the 30% of BNM it does not own in return for 30 million shares in Tethys, and making BNM a wholly owned subsidiary of TKL. TKL s interest in BNM is currently the principal asset of Tethys. Following this share swap there will be approximately 134.7 million shares in Tethys of which CanArgo will own 70 million (52 %).

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

The information required by this Item is hereby incorporated by reference from our definitive proxy statement to be mailed to stockholders in connection with our 2007 Annual Meeting of Stockholders and filed with the SEC within 120 days after the close of our fiscal year.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is hereby incorporated by reference from our definitive proxy statement to be mailed to stockholders in connection with our 2007 Annual Meeting of stockholders and filed with the SEC within 120 days after the close of our fiscal year.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information required by this Item is hereby incorporated by reference from our definitive proxy statement to be mailed to stockholders in connection with our 2007 Annual Meeting of Stockholders and filed with the SEC within 120 days after the close of our fiscal year.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required by this Item is hereby incorporated by reference from our definitive proxy statement to be mailed to stockholders in connection with our 2007 Annual Meeting of Stockholders and filed with the SEC within 120 days after the close of our fiscal year.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by this Item is hereby incorporated by reference from our definitive proxy statement to be mailed to stockholders in connection with our 2007 Annual Meeting of Stockholders and filed with the SEC within 120 days after the close of our fiscal year.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) Financial Statements

The following financial statements and related notes of the Company contained on pages F-1 through F- 61 are filed as part of this Report:

Reports of Independent Auditors
Consolidated Balance Sheets December 31, 2006 and 2005.
Consolidated Statements of Operations Years Ended December 31, 2006, 2005, and 2004.
Consolidated Statements of Cash Flows Years Ended December 31, 2006, 2005, and 2004.
Consolidated Statements of Stockholders Equity Years ended December 31, 2006, 2005 and 2004.
Notes to Consolidated Financial Statements

(2) Financial Statements Schedules

None

All other schedules are omitted because of the absence of conditions under which they are required or because the required information is included in the consolidated financial statements or notes thereto.

(b) Exhibits

	Management Contracts, Compensation Plans and Arrangements are identified by an asterisk (*) Documents filed herewith are identified by a cross ( ).
1(1)	Engagement Agreement with Sundal Collier & Co ASA dated August 13, 2001. (Incorporated herein by reference from Post-Effective Amendment No. 2 to Form S-1 Registration Statement, File No. 333-85116 filed on September 10, 2002)).
1(2)	Placement Agent Agreement dated September 22, 2004 by and between ABG Sundal Collier, Norge ASA and CanArgo Energy Corporation (Incorporated herein by reference from Amendment No 2 to Registration Statement on Form S-3 filed August 31, 2004 (Reg. No. 333-115645)).
1(3)	Placement Agent Agreement dated September 22, 2004 by and between ABG Sundal Collier Inc. and CanArgo Energy Corporation (Incorporated herein by reference from Amendment No 1 to Registration Statement on Form S-3 filed July 1, 2004 (Reg. No. 333-115645)).
1(4)	Engagement letter between ABG Sundal Collier Norge ASA and CanArgo Energy Corporation dated March 23, 2004 (Incorporated herein by reference from September 30, 2004 Form 10-Q).
†1(5)	Mandate Agreement dated September 19, 2006 by and among CanArgo Energy Corporation, Terra Securities ASA and Orion Securities ASA as amended by Addendum No. 1 dated September 21, 2006.

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2(4)	Memorandum of Agreement between Fielden Management Services Pty, Ltd., A.C.N. 005 506 123 and Fountain Oil Incorporated dated May 16, 1995 (Incorporated herein by reference from December 31, 1997 Form 10-K/A).
3(1)	Registrant s Certificate of Incorporation and amendments thereto (Incorporated by reference from the Company s Proxy Statements filed May 10, 1999 and May 9, 2000 and Form 8-K filed July 24, 1998 and May 23, 2006 and March 31, 2004 Form 10-Q filed on May 17, 2004).
3(2)	Registrant s Amended and Restated Bylaws as amended (Incorporated herein by reference to Form 8-K dated March 2, 2007).
*4(1)	Amended and Restated 1995 Long-Term Incentive Plan (Incorporated herein by reference fromSeptember 30, 1998 Form 10-Q).
*4(2)	Amended and Restated CanArgo Energy Inc. Stock Option Plan (Incorporated herein by reference from March 31, 1998 Form 10-Q).
*4(3)	CanArgo Energy Corporation 2004 Long Term Incentive Plan (Incorporated herein by reference from Form 8-K dated May 19, 2004 and Company s definitive Proxy Statement filed March 17, 2006).
4(4)	Amended and Restated Loan and Warrant Agreement between CanArgo Energy Corporation and Salahi Ozturk dated August 27, 2004 (Incorporated herein by reference from Form 8-K dated August 27, 2004)
4(5)	Note Purchase Agreement dated July 25, 2005 among CanArgo Energy Corporation and Ingalls & Snyder Value Partners, L.P. together with the other Purchasers (Incorporated herein by reference from Form 8-K/A dated July 28, 2005).
4(6)	Registration Rights Agreement dated July 25, 2005 among CanArgo Energy Corporation and Ingalls & Snyder Value Partners, L.P. together with the other Purchasers (Incorporated herein by reference from Form 8-K dated July 27, 2005).
4(7)	Note and Warrant Purchase Agreement dated March 3, 2006 among CanArgo Energy Corporation and the Purchasers party thereto (Incorporated herein by reference from Form 8-K dated March 8, 2006).
4(8)	Registration Rights Agreement dated March 3, 2006 among CanArgo Energy Corporation and the Purchasers party thereto (Incorporated herein by reference from Form 8-K dated March 8, 2006).
4(9)	Note and Warrant Purchase Agreement dated June 28, 2006 among CanArgo Energy Corporation and the Purchaser party thereto (Incorporated by reference from Form 8-K dated June 28, 2006).
4(10)	Registration Rights Agreement dated June 28, 2006 among CanArgo Energy Corporation and the Purchaser party thereto (Incorporated by reference from Form 8-K dated June 28, 2006).
4(11)	Form of Subscription Agreement dated as of September 19, 2006 by and between CanArgo Energy Corporation and the Purchaser named therein (Incorporated by reference from Form 8-K dated October 12, 2006).
10(1)	Production Sharing Contract between (1) Georgia and (2) Georgian Oil and JKX

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	Ninotsminda Ltd. dated February 12, 1996 (Incorporated herein by reference from Form S-1 Registration Statement, File No. 333-72295 filed on June 7, 1999).
*10(2)	Management Services Agreement between CanArgo Energy Corporation and Vazon Energy Limited relating to the provisions of the services of Dr. David Robson dated June 29, 2000 (Incorporated herein by reference from September 30, 2000 Form 10-Q). As amended by Deed of Variation of Management Services Agreement between CanArgo Energy Corporation and Vazon Energy Limited dated May 2, 2003 (Incorporated herein by reference to Form 8-K dated May 13, 2003).
10(3)	Tenancy Agreement between CanArgo Energy Corporation and Grosvenor West End Properties dated September 8, 2000 (Incorporated herein by reference from September 30, 2000 Form 10-Q).
10(4)	Production Sharing Contract between (1) Georgia and (2) Georgian Oil and CanArgo Norio Limited dated December 12, 2000 (Incorporated herein by reference from December 31, 2000 Form 10-K).
*10(5)	Service Agreement between CanArgo Energy Corporation and Vincent McDonnell dated December 1, 2000 (Incorporated herein by reference from December 31, 2001 Form 10-K).
10(6)	Sale agreement of CanArgo Petroleum Products Limited between CanArgo Limited and Westrade Alliance LLC dated October 14, 2002. (Incorporated herein by reference from September 30, 2002 Form 10-Q)
10(7)	Stock Purchase Agreement dated September 24, 2003 regarding the sale of all of the issued and outstanding stock of Fountain Oil Boryslaw (Incorporated herein by reference from March 31, 2003 Form 10-Q)
10(8)	Agreement between CanArgo Samgori Limited and Georgian Oil Samgori Limited dated January 8, 2004 (Incorporated herein by reference from Form S-3 filed May 6, 2004 (Reg. No. 333-115261)).
10(9)	Agreement dated March 17, 2004 between CanArgo Acquisition Corporation and Stanhope Solutions Ltd for the sale of Lateral Vector Resources Ltd. (Incorporated herein by reference from Form 8-K dated May 19, 2004).
10(10)	Master Service Contract dated June 1, 2004 between CanArgo Energy Corporation and WEUS Holding Inc. (Incorporated herein by reference from Form 8-K dated June 1, 2004).
10(11)	Agreement between Ninotsminda Oil Company Limited and Saipem S.p.A. dated January 27, 2005 (Incorporated herein by reference from Form 8-K dated January 27, 2005).
10(12)	Agreement between Ninotsminda Oil Company Limited and Primrose Financial Group dated February 4, 2005 (Incorporated herein by reference from Form 8-K dated February 4, 2005).
10(13)	Subsidiary Guaranty dated July 25, 2005 by and among Ninotsminda Oil Company Limited, CanArgo (Nazvrevi) Limited, CanArgo Norio Limited, CanArgo Limited, CanArgo Samgori Limited, Tethys Petroleum Investments Limited and CanArgo Ltd for the benefit of the holders of the Senior Secured Notes (Incorporated herein by reference from Form 8-K dated July 27, 2005).

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10(14)	Security Agreement dated July 25, 2005 among Ingalls & Snyder Value Partners, L.P. together with the other Purchasers (Incorporated herein by reference from Form 8-K dated July 27, 2005).
10(15)	Agreement dated July 25, 2005 among CanArgo Limited and Ingalls & Snyder Value Partners, L.P. together with the other Purchasers (Incorporated herein by reference from Form 8-K dated July 27, 2005).
10(16)	Security Interest Agreement (Securities) dated July 25, 2005 among CanArgo Ltd, CanArgo Limited, Ingalls & Snyder LLC as Security Agent for the Secured Parties (Incorporated herein by reference from Form 8-K dated July 27, 2005).
10(17)	Security Interest Agreement (Securities) dated July 25, 2005 among Tethys Petroleum Investments Limited, CanArgo Limited, Ingalls & Snyder LLC, as Security Agent for the Secured Parties and the Secured Parties (Incorporated herein by reference from Form 8-K dated July 27, 2005).
10(18)	Security Interest Agreement (Bank Account) dated July 25, 2005 by and among CanArgo Energy Corporation, Ingalls & Snyder LLC, as Security Agent for the Secured Parties and the Secured Parties (Incorporated herein by reference from Form 8-K dated July 27, 2005).
10(19)	Subordinated Subsidiary Guaranty dated March 3, 2006 by and among Ninotsminda Oil Company Limited, CanArgo (Nazvrevi) Limited, CanArgo Norio Limited, CanArgo Limited, Tethys Petroleum Investments Limited, Tethys Kazakhstan Limited and CanArgo Ltd for the benefit of the holders of the Subordinated Notes (Incorporated herein by reference from Form 8-K dated March 8, 2006).
10(20)	Subordinated Subsidiary Guaranty dated June 28, 2006 by and among Ninotsminda Oil Company Limited, CanArgo (Nazvrevi) Limited, CanArgo Norio Limited, CanArgo Limited, Tethys Petroleum Investments Limited, Tethys Kazakhstan Limited and CanArgo Ltd for the benefit of the holder of the 12% Subordinated Note (Incorporated herein by reference from Form 8-K dated June 28, 2006).
10(21)	Waiver, Consent and Amendment Agreement dated March 3, 2006 by and among CanArgo Energy Corporation and and the Purchasers party thereto (Incorporated herein by reference from Form 8-K dated March 8, 2006).
10(22)	Waiver, Consent and Amendment Agreement dated June 28, 2006, by and among CanArgo Energy Corporation and the Senior Secured Noteholders party thereto (Incorporated by reference from September 30, 2006 Form 10-Q).
10(23)	Waiver, Consent and Amendment Agreement dated June 28, 2006, by and among CanArgo Energy Corporation and the Senior Secured Noteholders party thereto (Incorporated by reference from September 30, 2006 Form 10-Q).
10(24)	Conversion Agreement dated June 28, 2006, by and among CanArgo Energy Corporation, the Subordinated Noteholders and Persistency (Incorporated by reference from Form 8-K dated June 28, 2006).
10(25)	Gas Supply Contract between BN Munai LLP and Gaz Impex S.A. LLP dated January 5, 2006 (Incorporated herein by reference from Form 8-K dated January 5, 2006)
10(26)	

Memorandum of Understanding dated as of March 2, 2006 by and between the Ministry of Energy of Georgia and CanArgo (Nazvrevi) Limited (Incorporated herein by reference from Form 8-K dated March 8, 2006)

10(27) Form of Management Services Agreement for Elizabeth Landles, Executive Vice President and Corporate Secretary dated February 18, 2004 (Incorporated by reference from Form 10-K dated March 16, 2006).

10(28) Service Contract between CanArgo Energy Corporation and Jeffrey Wilkins dated August 22, 2006 (Incorporated by reference from September 30, 2006 Form 10-Q).

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10(29)	Amendment, Consent, Waiver and Release Agreement dated February 9, 2007 by and among CanArgo Energy Corporation and the Purchasers party thereto (Incorporated by reference from Form 8-K dated January 24, 2007).
10(30)	Certificate of Discharge dated February 9, 2007 between Ingalls & Snyder LLC and CanArgo Limited (Incorporated by reference from Form 8-K dated January 24, 2007).
10(31)	Security Interest Agreement, dated as of February 9, 2007, among Tethys Petroleum Limited, Ingalls & Snyder LLC and the Secured Parties, as defined herein (Incorporated by reference from Form 8-K dated January 24, 2007).
10(32)	Amendment, Consent, Waiver and Release Agreement dated February 9, 2007 by and among CanArgo Energy Corporation and the Purchasers party thereto (Incorporated by reference from Form 8-K dated January 24, 2007).
10(33)	Amendment, Consent, Waiver and Release Agreement dated February 9, 2007 by and among CanArgo Energy Corporation and Persistency (Incorporated by reference from Form 8-K dated January 24, 2007).
10(34)	Tethys Shareholders Agreement dated as of January 24, 2007 by and among CanArgo Limited, the Investors party thereto and Tethys Petroleum Limited.
10(35)	Share Exchange Agreement relating to BN Munai LLP between Coin Investments Limited, Tethys Petroleum Limited and Tethys, Kazakhstan Limited.
14	Code of Ethics (Incorporated herein by reference from December 31, 2004 Form 10-K).
21	List of Subsidiaries (Incorporated herein by reference from June 30, 2005 Form 10-Q).
23(a)	Consent of L J Soldinger Associates, LLC, Independent Public Accountants.
23(c)	Consent of Oilfield Production Consultants (OPC) Limited, Independent Petroleum Consultants.
31(1)	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer of CanArgo Energy Corporation.
31(2)	Rule 13a-14(c)/15d-14(a) Certification of Chief Financial Officer of CanArgo Energy Corporation.
32	Section 1350 Certifications.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CanArgo Energy Corporation
(Registrant)

By:	/s/ Jeffrey Wilkins	Date: March 15, 2007
	Chief Financial Officer (Principal Financial and Accounting Officer)	

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

By:	/s/ David Robson	Date: March 15, 2007
	David Robson, Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)	
By:	/s/ Vincent McDonnell	Date: March 15, 2007
	Vincent McDonnell, President, Chief Operating Officer, Chief Commercial Officer and Director	
By:	/s/ Michael Ayre	Date: March 15, 2007
	Michael Ayre, Director	
By:	/s/ Russell Hammond	Date: March 15, 2007
	Russell Hammond, Director	
By:	/s/ Nils N. Trulsvik	Date: March 15, 2007
	Nils N. Trulsvik, Director	

EXHIBIT INDEX

1(5)	Mandate Agreement dated September 19, 2006 by and among CanArgo Energy Corporation, Terra Securities ASA and Orion Securities ASA as amended by Addendum No. 1 dated September 21, 2006.
10(34)	Tethys Shareholders Agreement dated as of January 24, 2007 by and among CanArgo Limited, the Investors party thereto and Tethys Petroleum Limited.
10(35)	Share Exchange Agreement relating to BN Munai LLP between Coin Investments Limited, Tethys Petroleum Limited and Tethys Kazakhstan Limited.
23(a)	Consent of L J Soldinger Associates, LLC, Independent Public Accountants.
23(c)	Consent of Oilfield Production Consultants (OPC) Limited, Independent Petroleum Consultants.
31(1)	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer of CanArgo Energy Corporation.
31(2)	Rule 13a-14(c)/15d-14(a) Certification of Chief Financial Officer of CanArgo Energy Corporation.
32	Section 1350 Certifications.

CANARGO ENERGY CORPORATION

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REPORT ON MANAGEMENT S RESPONSIBILITIES

To the Stockholders of CanArgo Energy Corporation:

CanArgo s management is responsible for the integrity and objectivity of the financial information contained in this Annual Report. The financial statements included in this report have been prepared in accordance with accounting principles generally accepted in the United States and, where necessary, reflect the informed judgements and estimates of management.

Management maintains and is responsible for systems of internal accounting control designed to provide reasonable assurance that all transactions are properly recorded in the Company s books and records, that procedures and policies are adhered to, and that assets are safeguarded from unauthorized use.

The financial statements for 2006 and 2005 have been audited by the independent accounting firm of L J Soldinger Associates LLC, as indicated in their report. Management has made available to its outside auditors all the Company s financial records and related data and minutes of directors and audit committee meetings.

CanArgo s audit committee, consisting solely of directors who are not employees of CanArgo, is responsible for: reviewing the Company s financial reporting; reviewing accounting and internal control practices; recommending to the Board of Directors and shareholders the selection of independent accountants; and monitoring compliance with applicable laws and company policies. The independent accountants have full and free access to the audit committee and meet with it, with and without the presence of management, to discuss all appropriate matters. On the recommendation of the audit committee, the consolidated financial statements have been approved by the Board of Directors.

/s/ Dr. David Robson	/s/ Jeffrey Wilkins
Chief Executive Officer	Chief Financial Officer
March 15, 2007	

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
CanArgo Energy Corporation
St Peter Port, Guernsey, British Isles

We have audited the accompanying consolidated balance sheets of CanArgo Energy Corporation as of December 31, 2006 and 2005, and the related consolidated statements of operations and comprehensive income, stockholders equity, and cash flows for each of the years in the three-year period ended December 31, 2006. 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 audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about 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 statements presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of CanArgo Energy Corporation as of December 31, 2006 and 2005, and its consolidated results of operations, changes in stockholders equity and its cash flows for each of the years in the three-year period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America.

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 to the financial statements, the Company has incurred net losses since inception. Also, the Company may not have sufficient funds to execute its business plan. These conditions raise substantial doubt about the Company s ability to continue as a going concern. Management s plans regarding those matters are also described in Note 1. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of CanArgo Energy Corporation internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated 10 March, 2007 expressed an unqualified opinion on management s assessment of internal control over financial reporting and an adverse opinion on the effectiveness of internal control over financial reporting.

L J SOLDINGER ASSOCIATES LLC
Deer Park, Illinois, USA
March 10, 2007

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CANARGO ENERGY CORPORATION
Consolidated Balance Sheets

	December 31, 2006	December 31, 2005
	(Expressed in United States dollars)	
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 16,452,550**	$ 18,540,558
Restricted cash	**299,777**	3,181,672
Accounts receivable	**509,323**	413,183
Crude oil inventory	**452,500**	886,250
Prepayments	**6,443,417**	4,375,855
Assets to be disposed	**7,856**	5,112
Assets held for sale		600,000
Other current assets	**163,561**	150,712
Total current assets	**$ 24,328,984**	$ 28,153,342
Non Current Assets		
Investments	**205,484**	
Accounts receivable	**1,086,350**	
Prepaid financing fees	**318,682**	246,910
Capital assets, net (including unevaluated amounts of $68,313,162 and $50,644,999, respectively)	**110,545,982**	119,048,049
Total Assets	**$ 136,485,482**	$ 147,448,301
LIABILITIES AND STOCKHOLDERS EQUITY		
Accounts payable trade	**$ 4,460,312**	$ 5,270,916
Loans payable		964,142
Deferred revenue	**484,515**	
Accrued liabilities	**7,387,230**	6,356,623
Liabilities to be disposed	**368,939**	753,966
Total current liabilities	**$ 12,700,996**	$ 13,345,647
Long term debt	**40,347,943**	25,000,000
Other non current liabilities	**1,291,794**	1,001,041
Provision for future site restoration	**655,867**	253,000
Total Liabilities	**$ 54,996,600**	$ 39,599,688

Commitments and contingencies		
Temporary Equity	**$ 2,119,530**	$ 2,119,530
Stockholders equity:		
Common stock, par value $0.10; authorized - 375,000,000 shares at December 31, 2006 and 300,000,000 at December 31, 2005; shares issued, issuable and outstanding - 237,145,974 at December 31, 2006 and 222,586,867 at December 31, 2005	**23,714,596**	22,258,685
Capital in excess of par value	**233,397,113**	202,892,303
Deferred compensation expense		(2,220,399)
Accumulated deficit	**(177,742,357)**	(117,201,506)
Total stockholders equity	**$ 79,369,352**	$ 105,729,083
Total Liabilities, Temporary Equity and Stockholders Equity	**$ 136,485,482**	$ 147,448,301

The accompanying notes are an integral part of the consolidated financial statements

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CANARGO ENERGY CORPORATION
Consolidated Statements of Operations and Comprehensive Loss

	For Year Ended December 31,		
	December 31, 2006	December 31, 2005	December 31, 2004
	(Expressed in United States dollars)		
Operating Revenues from Continuing Operations:			
Oil and gas sales	**$ 6,526,660**	$ 5,278,912	$ 7,832,894
	6,526,660	5,278,912	7,832,894
Operating Expenses:			
Field operating expenses	**1,702,679**	1,109,588	1,829,058
Direct project costs	**811,795**	1,084,330	1,098,115
Selling, general and administrative	**14,817,321**	11,553,673	7,492,078
Depreciation, depletion and amortization	**3,831,472**	3,275,553	2,881,020
Impairment of oil and gas properties, ventures and other assets	**39,000,000**		174,812
Income on dispositions			(1,606,274)
	60,163,267	17,023,144	11,868,809
Operating Loss from Continuing Operations	**(53,636,607)**	(11,744,232)	(4,035,915)
Other Income (Expense):			
Interest income	**700,529**	827,204	52,868
Interest and amortization of debt discount and expense	**(7,500,659)**	(1,899,522)	(953,363)
Foreign exchange gains (losses)	**291,589**	33,341	(330,265)
Other	**(1,068,506)**	(259)	(789,596)
Equity Loss from investments		(155,016)	(205,230)
Total Other Expense	**(7,577,047)**	(1,194,252)	(2,225,586)
Loss from Continuing Operations Before Taxes	**(61,213,654)**	(12,938,484)	(6,261,501)
Income taxes			
Loss from Continuing Operations	**(61,213,654)**	(12,938,484)	(6,261,501)
Net Income (Loss) from Discontinued Operations, net of taxes	**672,803**	603,170	1,504,007
Net Loss and Comprehensive Loss	**$ (60,540,851)**	$ (12,335,314)	$ (4,757,494)

Weighted average number of common shares outstanding			
- Basic	**227,001,672**	211,586,953	134,005,490
- Diluted	**227,001,672**	211,586,953	134,005,490
Basic and Diluted Net Loss Per Common Share			
- from continuing operations	**$ (0.27)**	$ (0.06)	$ (0.05)
- from discontinued operations	$ 0.00	$ 0.00	$ 0.01
Basic and Diluted Net Loss Per Common Share	**$ (0.27)**	$ (0.06)	$ (0.04)
Other Comprehensive Income (Loss):			
Foreign currency translation			146,463
Comprehensive Loss	**$ (60,540,851)**	$ (12,335,314)	$ (4,611,031)

The accompanying notes are an integral part of the consolidated financial statements

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CANARGO ENERGY CORPORATION
Consolidated Statements of Cash Flows

	For Year Ended December 31,		
	2006	2005	2004
	(Expressed in United States dollars)		
Operating activities:			
Net Loss	**(60,540,851)**	(12,335,314)	(4,757,494)
Net income (loss) from discontinued operations, net of taxes and minority interest	**672,803**	603,170	1,504,007
Loss from continuing operations	**(61,213,654)**	(12,938,484)	(6,261,501)
Adjustments to reconcile net loss from continuing operations to net cash used by operating activities:			
Non-cash stock compensation expense	**1,924,076**	2,374,578	1,395,035
Non-cash interest expense and amortization of debt discount	**3,898,091**	1,277,878	653,313
Non-cash reduction in selling, general and administrative expenses			(300,000)
Non-cash debt extinguishment expense			349,923
Common stock issued for services		53,600	118,400
Non-cash miscellanous expenses		193,000	
Depreciation, depletion and amortization	**3,831,472**	3,275,553	2,881,020
Impairment of oil and gas ventures and other assets	**39,000,000**		174,812
Equity loss (income) from investments		155,016	205,230
Gain on dispositions			(1,606,274)
Allowance for doubtful accounts		145,829	5,803
Changes in assets and liabilities:			
Restricted cash	**2,881,895**	(1,781,672)	(1,400,000)
Cash Investments	**(205,484)**		
Accounts receivable	**(1,182,490)**	2,146,016	(1,408,016)
Inventory	**433,750**	(632,392)	214,935
Prepayments	**(80,461)**	(202,801)	(12,560)
Other current assets	**(12,849)**	(29,102)	84,922
Accounts payable	**851,123**	757,401	1,359,576
Deferred revenue	**484,515**	(3,080,839)	(449,255)
Income taxes payable			(97,500)
Accrued liabilities	**69,807**	(585,542)	(219,558)
Net cash used by continuing operating activities	**(9,320,209)**	(8,871,961)	(4,311,695)
Investing activities:			
Capital expenditures	**(35,277,909)**	(33,450,583)	(11,190,290)
Acquisitions, net of cash acquired		609,553	
Proceeds from disposition of subsidiary			2,107,001
Investments in oil and gas and other ventures			(383,862)
Change in oil and gas supplier prepayments	**(1,900,733)**	(855,466)	(499,933)

Net cash used in investing activities	**(37,178,642)**	(33,696,496)	(9,967,084)
Financing activities:			
Proceeds from sale of common stock	**17,267,280**	4,429,303	37,999,516
Share issue costs	**(1,146,236)**	(191,875)	(4,543,845)
Deferred offering costs			(309,318)
Advances from joint venture partner			290,000
Payments of joint venture obligations			(1,063,146)
Proceeds from loans	**28,000,000**	39,237,000	3,806,000
Repayment of loans		(7,200,000)	(1,408,179)
Deferred loan costs	**(289,233)**	(385,630)	
Net cash provided by financing activities	**43,831,811**	35,888,798	34,771,028
Discontinued activities:			
Net cash generated by operating activities	**579,032**	603,170	2,034,624
Net cash used in investing activities			(1,382,078)
Net cash provided by financing activities			
Net cash flows from assets and liabilities held for sale and to be disposed	**579,032**	603,170	652,546
Net increase (decrease) in cash and cash equivalents	**(2,088,008)**	(6,076,489)	21,144,795
Cash and cash equivalents, beginning of period	**18,540,558**	24,617,047	3,472,252
Cash and cash equivalents, end of period	**$ 16,452,550**	$ 18,540,558	$ 24,617,047

The accompanying notes are an integral part of the consolidated financial statements

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CANARGO ENERGY CORPORATION
Consolidated Statements of Stockholders Equity

	Common Stock Number of Shares Issued and Issuable	Par Value	Additional Paid-In Capital	Deferred Compensation Expense	Foreign Currency Translation	Accumulated Deficit	Total Stockholders Equit
			Expressed in United States Dollars				
Total, December 31, 2003	**105,617,988**	**$ 10,561,798**	**$ 146,401,804**	**$**	**$ (146,463)**	**$ (100,108,698)**	**$ 56,708,441**
Current year adjustment					146,463		146,463
Exercise of stock options and warrants	3,815,084	381,508	118,008				499,516
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	163,218	16,322	79,446				95,768
Shares Issued pursuant to Standby Equity Distribution agreement (Newbridge Securities)	30,799	3,080	15,091				18,171
Shares Issued pursuant to consultancy agreement (Europa Oil Services Ltd)	4,000,000	400,000	3,480,000				3,880,000
Shares Issued pursuant to	80,000	8,000	49,600				57,600

consultancy agreement (CEOCast)					
Issue of Warrants to purchase 1 million			754,000		754,000
Issue of Warrants to purchase 300,000 shares pursuant to a Loan agreement			197,040		197,040
Stock based compensation under SFAS 148			2,647,858	(1,976,102)	671,756
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	425,000	42,500	182,750		225,250
Issue of Warrants to purchase 1 million shares pursuant to a Loan agreement			263,786		263,786
Shares Issued pursuant to Global public offering	75,000,000	7,500,000	30,000,000		37,500,000
Share ssue costs			(4,543,845)		(4,543,845)
Shares Issued pursuant to CanArgo	6,000,000	600,000	3,720,000		4,320,000

Norio Limited Buy-Out							
Shares Issueable pursuant to consultancy agreement (CEOCast)	80,000	8,000	52,800				60,800
Net Loss						(4,757,494)	(4,757,494)
Total, December 31, 2004	**195,212,089**	**$ 19,521,207**	**$ 183,418,338**	**$ (1,976,102)**	**$ 0**	**$ (104,866,192)**	**$ 96,097,251**

The accompanying notes are an integral part of the consolidated financial statements

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	Common Stock Number of Shares Issued and Issuable	Par Value	Additional Paid-In Capital	Deferred Compensation Expense	Foreign Currency Translation	Accumulated Deficit	Total Stcokholders Equity
			Expressed in United States Dollars				
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	380,836	38,084	469,514				507,598
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	335,653	33,565	458,837				492,402
Exercise of stock options	1,067,833	106,783	255,850				362,633
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	344,758	34,476	498,072				532,548
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	370,599	37,060	562,940				600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	381,170	38,117	561,883				600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	495,745	49,574	550,426				600,000
Exercise of stock options	1,570,000	157,000	11,000				168,000

Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	552,639	55,264	544,736	600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	473,634	47,363	552,637	600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	837,054	**83,705**	516,295	600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	813,670	**81,367**	518,633	600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	872,854	**87,285**	512,715	600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	847,458	**84,746**	515,254	600,000
Shares Issueable pursuant to consultancy agreement (CEOCast)	80,000	8,000	45,600	53,600
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	801,068	**80,107**	519,893	600,000
Shares Issued pursuant to Standby	812,348	**81,235**	518,765	600,000

Equity Distribution agreement (Cornell Capital)				
Shares Issued pursuant to Tethys buy-out	11,000,000	1,100,000	7,260,000	8,360,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	639,591	**63,959**	536,041	600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	596,421	**59,642**	540,358	600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	613,246	**61,325**	538,675	600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	630,120	**63,012**	536,988	600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	669,568	**66,957**	533,043	600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	761,325	**76,133**	523,867	600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	783,188	**78,319**	521,681	600,000

The accompanying notes are an integral part of the consolidated financial statements

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CANARGO ENERGY CORPORATION
Consolidated Statements of Stockholders Equity continued

	Common Stock Number of Shares Issued and Issuable	Par Value	Additional Paid-In Capital	Deferred Compensation Expense	Foreign Currency Translation	Accumulated Deficit	Total Stockholders Equit
			Expressed in United States Dollars				
Exercise of stock options	360,000	36,000	481,320				517,320
Exercise of stock options	284,000	28,400	352,950				381,350
Stock based compensation under SFAS 148			1,222,625	(244,297)			978,328
Share issue costs			(1,186,633)				(1,186,633)
Net Loss						(12,335,314)	(12,335,314)
Total, December 31, 2005	**222,586,867**	**$ 22,258,685**	**$ 202,892,303**	**$ (2,220,399)**		**$ (117,201,506)**	**$ 105,729,083**

	Common Stock Number of Shares Issued and Issuable	Par Value	Additional Paid-In Capital	Deferred Compensation Expense	Accumulated Deficit	Total Stockholders Equity
Total, December 31, 2005	**222,586,867**	**$22,258,685**	**$202,892,303**	**$(2,220,399)**	**$(117,201,506)**	**$105,729,083**
Shares Issued pursuant to amended loan agreement dated August 27, 2004 (Salahi Ozturk)	1,521,739	152,174	897,826			1,050,000
Adoption of FAS 123R stock based compensation on effective date			(2,220,399)	2,220,399		
Discount recorded for Beneficial conversion feature and Issue of warrants to purchase 13 million shares persuant to a convertible loan agreement			10,166,000			10,166,000

Discount recorded for Beneficial conversion feature and Issue of warrants to purchase 12.5 million shares persuant to a convertible loan agreement			2,700,000			2,700,000
Stock based compensation under SFAS 123R			1,924,076			1,924,076
Discount recorded for Issue of warrants to purchase 5 million shares persuant to a loan agreement			2,220,000			2,220,000
Exercise of stock options	774,000	77,400	511,700			589,100
Shares Issued persuant to private placement October 2006	12,263,368	1,226,337	15,451,843			16,678,180
Share issuance costs			(1,146,236)			(1,146,236)
Net Loss					(60,540,851)	(60,540,851)
Total, December 31, 2006	**237,145,974**	**$ 23,714,596**	**$ 233,397,113**	**$ 0**	**$ (177,742,357)**	**$ 79,369,352**

The accompanying notes are an integral part of the consolidated financial statements

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NOTE 1 NATURE OF OPERATIONS AND GOING CONCERN

CanArgo Energy Corporation, headquartered in Guernsey, British Isles, and its consolidated subsidiaries (collectively CanArgo , we , our , us), is an integrated oil and gas company operating predominately within Georgia a the Republic of Kazakhstan. Our principal activity is the acquisition of interests in and development of crude oil and natural gas fields.

In 2002 and 2003, we approved a plan to sell CanArgo Standard Oil Products Limited (CSOP), Lateral Vector Resources Inc. (LVR), the Georgian American Oil Refinery Limited (GAOR). During 2004, CSOP, GAOR and LVR were sold. The results of these operations have been classified as discontinued for all periods presented. Net income (loss) from discontinued operations is disclosed net of taxes and minority interest for all periods presented.

The accompanying financial statements have been prepared in accordance with U.S. GAAP, which contemplates continuation of the Company as a going concern. The Company incurred net losses from continuing operations to common stockholders of approximately $61,214,000, $12,938,000 and $6,262,000 for the years ended December 31, 2006, 2005 and 2004 respectively. These net losses included non-cash charges related to depreciation and depletion, impairments, loan interest, amortization of debt discount and stock-based compensation of approximately $48,653,000, $6,928,000 and $5,104,000 for the years ended December 31, 2006, 2005 and 2004 respectively. In addition, the amount of cash needed for 2007 operations exceeds the amount of cash held by the Company at December 31, 2006.

In the years ended December 31, 2006 and 2005 the Company s revenues from its Georgian operations did not cover the costs of its operations. At December 31, 2006 the Company had unrestricted cash and cash equivalents available for general corporate use or for use in the Georgian operations of approximately $14,780,000. In 2006 the Company experienced a net cash outflow from operations of approximately $17,883,000 in Georgia. In addition, the Company has a planned capital expenditure budget in 2007 of approximately $5,200,000 in Georgia. In the event that the exploration and development wells currently undergoing or waiting to undergo production testing in Georgia fail to produce enough commercially available quantities of oil and or gas, the Company may not have sufficient working capital and may have to delay or suspend its capital expenditure plans and possibly make cutbacks in its operations. There are no assurances the Company could raise additional sources of equity financing and because of the covenants contained in the Senior Secured Convertible Notes (see Note 11) the Company is restricted from incurring additional debt obligations unless it receives consent from at least 51% of the noteholders, which cannot be assured. Consequently, the aforementioned items raise substantial doubt about the Company s ability to continue as a going concern.

The Company believes that if it is able to successfully complete the Manavi 12 well in the second quarter such that a significant quantity of oil flows are produced, that it will be able to raise additional debt and or equity funds in order to continue operations and to properly develop the Manavi field and continue working on the Norio and Ninotsminda fields.

In October 2006, CanArgo Limited, a wholly owned subsidiary of the Company, converted all of its outstanding loans due from Tethys into 69,999,900 shares of Tethys share capital. In February 2007 we announced that Tethys had completed a private placement with a limited group of private investors raising gross proceeds of approximately $17.35 million, by issuing in total approximately 34.7 million new ordinary shares in Tethys, these representing approximately 33% of the issued and outstanding share capital of Tethys, and with us retaining our 70,000,000 shares in Tethys, these representing the remaining 67%. Under the terms of previous subordinated debt issuances by the Company (see Note 11), CanArgo Energy Corporation is restricted from using any of the cash held by Tethys or its subsidiaries for general corporate use nor is it able to use those funds for the drilling program in Georgia so long as there is principal outstanding under those notes. Under the terms of the Shareholders Agreement entered into with the new private investors, Tethys is subject to certain positive and negative covenants which require the consent of the holders of not less than 75% of the ordinary shares in issue in Tethys from time to time (the Shareholder Majority). The Agreement also outlines certain provisions in relation to the conduct of the Tethys business and provided that the intention of Tethys, CanArgo Limited and the Investors is to use their reasonable endeavors to work towards a listing of Tethys as soon as practicable, subject to

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(i) the financial and commercial circumstances of Tethys, and the pre-money valuation of Tethys prior to the listing being acceptable to the Shareholder Majority; and (ii) the terms and amounts (if any) raised by Tethys on such listing being acceptable to the board of Tethys. With the completion of the private placement in February 2007, we have fully funded the currently planned budget for our operating and development expenditure in Kazakhstan for 2007.

The Company s ability to continue as a going concern is dependent upon raising capital through debt and equity financing on terms desirable to the Company. If the Company is unable to obtain additional funds when they are required or if the funds cannot be obtained on terms favorable to the Company, management may be required to delay, scale back or eliminate its well development program or license third parties to develop or market products that the Company would otherwise seek to develop or market itself, or even be required to relinquish its interest in the properties or in the extreme situation, cease operations. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The consolidated financial statements and notes thereto are prepared in accordance with accounting principles generally accepted in the United States. All amounts are in U.S. dollars. Certain items for prior years in the consolidated financial statements have been reclassified to conform to the current year s presentation. There was no effect on the reported net loss as a result of these reclassifications.

Consolidation

The consolidated financial statements include the accounts of CanArgo Energy Corporation and its majority owned subsidiaries. All significant intercompany transactions and accounts have been eliminated. Investments in less than majority owned corporations and corporate like entities in which we exercises significant influence are accounted for using the equity method. Entities in which we do not have significant influence are accounted for using the cost method.

Equity Method

Under the guidance of Emerging Issue Task Force D-46, Accounting for Limited Partnership Investments the Company uses the equity method to account for all of its limited partnership interests in oil and gas ventures that exceed 5% and is less than 50%. Under the equity method of accounting, the Company s proportionate share of the investees net income or loss is included in Equity Income from Investments in the consolidated statements of operations. Any excess of the carrying value of the investment and loan advances over the underlying net equity of the investee is evaluated each reporting period for impairment.

In accordance with Emerging Issues Task Force (EITF) 98-13 Accounting by an Equity Method Investor for Investee Losses When the Investor has Loans to and Investments in Other Securities of the Investee, and 99-10 Percentage Used to Determine the Amount of Equity Method Losses, in the event that minority interest losses exceed stockholders equity for the majority interest, the excess minority interest loss is recorded against loan advances or other forms of equity invested in the subsidiary. In accordance with the requirements of EITF 99-10 the Company has chosen to account for the percentage of losses to be applied to reduce its loan balance based on its ownership percentage and not on its relative percentage of investment in each security class across all investors.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates, judgements and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the

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reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Management believes that it is reasonably possible the following material estimates affecting the financial statements could significantly change in the coming year: (1) estimates of proved oil and gas reserves, (2) estimates as to the expected future cash flow from proved oil and gas properties, and (3) estimates of future dismantlement and restoration costs.

Cash and Cash Equivalents

Cash and cash equivalents include all liquid investments with an original maturity of three months or less.

Fair Value of Financial Instruments

The carrying amounts reflected in the consolidated balance sheets for cash and equivalents, short-term receivables and short-term payables approximate their fair value due to the short maturity of the instruments. For the balances in 2006, the carrying value of $40,347,943 of long-term debt reflects discounts for the value of detachable warrants and beneficial conversion features, net of amortization, of $12,652,057. The face amount of long-term debt outstanding as of December 31, 2006 was $53,000,000. Please refer to Note 11 Loans Payable and Long Term Debt for a more detailed discussion of the accounting treatment of the long-term debt. For 2005, the carrying value of the short-term note payable with detachable warrants reflects a discount for the value of warrants and was $964,142 at December 31, 2005. The face amount of the note payable was $1,050,000 at December 31, 2005. The carrying value of the short-term debt approximated fair value as the debt bears interest at a market rate.

Concentration of Credit Risk

Although our accounts receivable are exposed to potential credit loss, we do not believe such risk to be significant.

During the year ended December 31, 2006, oil produced in Georgia was sold to two customers with sales to one of these customers representing more than 10% of revenues. During the year ended December 31, 2005, oil produced in Georgia was sold to four customers with sales to two of these customers representing more than 10% of revenues.

As an independent oil and gas producer, our revenue, profitability and future rate of growth are substantially dependent upon prevailing prices for oil and gas, which are dependent upon numerous factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. The energy markets have historically been very volatile, and there can be no assurance that oil and gas prices will not be subject to wide fluctuations in the future. A substantial or extended decline in oil and gas prices could have a material adverse effect on our financial position, results of operations, cash flows and our access to capital and on the quantities of oil and gas reserves that may be economically produced.

Reclassification

Certain items in the consolidated financial statements have been reclassified to conform to the current year presentation. There was no effect on reported net loss as a result of these reclassifications.

Accounts Receivable and Allowance for Doubtful Debts

Accounts receivable are carried at the amount owed by customers, reduced by an allowance for estimated amounts that may not be collectible in the future. The allowance for doubtful accounts is estimated based upon historical write-off percentages, known problem accounts, and current economic conditions. Accounts are written off against the allowance for doubtful accounts when we determine that amounts are not collectable and recoveries of previously written-off accounts are recorded when collected.

Inventories

Inventories of crude oil are valued at the lower of average cost or net realizable value. Inventory costs include expenditures and other charges (including depreciation, depletion and amortization) directly and indirectly incurred in bringing the inventory to its existing condition and location. Selling expenses and general and administrative expenses are reported as period costs and excluded from inventory cost.

Capital Assets

Capital assets are recorded at cost less accumulated provisions for depreciation, depletion and amortization unless the carrying amount is viewed as not recoverable in which case the carrying value of the assets is reduced to the estimated recoverable amount. See Impairment of Long-Lived Assets below. Expenditures for major renewals and betterments, which extend the original estimated economic useful lives of applicable assets, are capitalized. Expenditures for normal repairs and maintenance are charged to expense as incurred. The cost and related accumulated depreciation of assets sold or retired are removed from the accounts and any gain or loss thereon is reflected in operations. Unproved properties are not deemed to be impaired until the right to drill on those properties is lost and/or planned development has ceased.

Oil And Gas Properties - CanArgo and the unconsolidated entities (for which it accounts using the equity method) account for oil and gas properties and interests under the full cost method. Under the full cost method, all acquisition, exploration and development costs, including certain directly related employee costs incurred for the purpose of finding oil and gas are capitalized and accumulated in pools on a country by country basis. Capitalized costs include the cost of drilling and equipping productive wells, including the estimated costs of dismantling and abandoning these assets, dry hole costs, lease acquisition costs, seismic and other geological and geophysical costs, delay rentals and costs related to such activities. Employee costs associated with production and other operating activities and general corporate activities are expensed in the period incurred.

Where proved reserves are established, capitalized costs are limited on a country by country basis (the ceiling test). The ceiling test is calculated as the sum of the present value of future net cash flows related to estimated production of proved reserves, using end of the-current-period prices, discounted at 10%, and takes into account expected future costs to develop proved reserves, and operating expenses and income taxes. Under the ceiling test, if the capitalized cost of the full cost pool exceeds the ceiling limitation, the excess is charged as an impairment expense.

Unit-of-production depreciation is applied to capitalized costs of the full cost pool. Unit-of-production rates are based on the amount of proved developed reserves of oil, gas and other minerals that are estimated to be recoverable from existing facilities using current operating methods.

We utilize a single cost center for each country where we have operations for amortization purposes. Any conveyances of properties are treated as adjustments to the cost of oil and gas properties with no gain or loss recognized unless the operations are suspended in the entire cost center or the conveyance is significant in nature.

The costs of investments in unproved properties and portions of costs associated with major development projects are excluded from the depreciation, depletion and amortization (DD&A) calculation until the project is evaluated.

Unproved property costs include leasehold costs, seismic costs and other costs incurred during the exploration phase. In areas where proved reserves are established, significant unproved properties are evaluated periodically, but not less than annually, for impairment. If a reduction in value has occurred, these property costs are considered impaired and are transferred to the related full cost pool. Unproved properties whose acquisition costs are not individually significant are aggregated, and the portion of such costs estimated to be ultimately nonproductive, based on experience, is amortized to the full cost pool over an average holding period.

In countries where the existence of proved reserves has not yet been determined, leasehold costs, seismic costs and other costs incurred during the exploration phase remain capitalized in unproved property cost centers until proved reserves have been established or until exploration activities cease or impairment and reduction in value occurs. If exploration activities result in the establishment of a proved reserve base, amounts in the unproved property cost center are reclassified as proved properties and become subject to depreciation, depletion and amortization and the application of the ceiling test. If exploration efforts in a country are unsuccessful in establishing proved reserves, it may be determined that the value of exploratory costs incurred there have been permanently diminished in part or in whole. Therefore, based on the impairment evaluation and future exploration plans, the unproved property cost centers related to the area of interest could be impaired, and accumulated costs charged against earnings.

Property and Equipment Depreciation of property and equipment is computed using the straight-line method over the estimated useful lives of the assets ranging from three to five years for office furniture and equipment to three to fifteen years for oil and gas related equipment.

Property and Equipment (CanArgo Standard Oil Products) Depreciation of property and equipment at CanArgo Standard Oil Products petrol stations and additions thereto were depreciated over the estimated useful lives of the assets ranging from ten to fifteen years until operations were reclassified as discontinued.

Revenue Recognition

Continuing operations We recognize revenues when hydrocarbons have been produced and delivered and payment is reasonably assured.

Discontinued operations We recognize revenues when goods have been delivered, when services have been performed, or when hydrocarbons have been produced and delivered and payment is reasonably assured.

Foreign Operations

Our future operations and earnings will depend upon the results of our operations in the Georgia. There can be no assurance that we will be able to successfully conduct such operations, and a failure to do so would have a material adverse effect on our financial position, results of operations and cash flows. Also, the success of our operations will be subject to numerous contingencies, some of which are beyond management control. These contingencies include general and regional economic conditions, prices for crude oil and natural gas, competition and changes in regulation. Since we are dependent on international operations, specifically those in Georgia, we will be subject to various additional political, economic and other uncertainties. Among other risks, our operations may be subject to the risks and restrictions on transfer of funds, import and export duties, quotas and embargoes, domestic and international customs and tariffs, and changing taxation policies, foreign exchange restrictions, political conditions and regulations.

Foreign Currency Translation

The U.S. dollar is the functional currency for our upstream operations and the Lari is the functional currency for marketing operations. All monetary assets and liabilities denominated in foreign currency are translated into U.S. dollars at the rate of exchange in effect at the balance sheet date and the resulting unrealized translation gains or losses are reflected in operations. Non-monetary assets are translated at historical exchange rates. Revenue and expense items (excluding depreciation and amortization which are translated at the same rates as the related assets) are translated at the average rate of exchange for the year.

Income Taxes

We recognize deferred tax liabilities and assets for the expected future tax consequences of events that have been included in the financial statements or tax returns. Deferred tax liabilities and assets are determined based on the difference between the financial statement and the tax bases of assets and liabilities using enacted rates in effect for the years in which the differences are expected to reverse. Valuation allowances are established, when appropriate, to reduce deferred tax assets to the amount expected to be realized.

Impairment of Long-Lived Assets

The Company evaluates its long-lived assets for impairment using the guidance of Statement of Financial Accounting Standard (SFAS) No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. SFAS No. 144 establishes a single accounting model for long-lived assets to be disposed of by sale and requires that those long-lived assets be measured at the lower of carrying amount or fair value less cost to sell, whether reported in continuing operations or in discontinued operations.

Dismantlement, Restoration and Environmental Costs

Effective January 1, 2003, we recognize liabilities for asset retirement obligations associated with tangible long-lived assets, such as producing well sites, with a corresponding increase in the related long-lived asset. The asset retirement cost is depleted along with the property and equipment in the full cost pool. The asset retirement obligation is recorded at fair value and accretion expense, recognized over the life of the property, increases the liability to its expected settlement value. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded for both the asset retirement obligation and the asset retirement cost. As at December 31, 2006 and December 31, 2005, the asset retirement obligation, which is included on the consolidated balance sheet in provision for future site restoration, was $656,000 and $226,000, respectively.

	2006	2005
Beginning balance, January 1	$ 226,000	$ 152,000
New obligations incurred in 2006	221,000	58,800
Liabilities settled in 2006		
Accretion of expense	22,000	15,200
Revision in estimates, including timing	187,000	
Balance at December 31	656,000	226,000

Stock-Based Compensation Plans

Effective January 1, 2006 the Company adopted Statement of Financial Accounting Standard (SFAS) No. 123 (revised 2004), Share Based Payment (SFAS No. 123(R)). Generally, the fair value approach in SFAS No. 123(R) is similar to the fair value approach described in SFAS No. 123. In 2005, we used the Black-Scholes option pricing model to estimate the fair value of stock options granted to employees. We adopted SFAS No. 123(R), using the modified-prospective method, beginning January 1, 2006. We also elected to continue to estimate the fair value of stock options using the Black-Scholes-option pricing model. Total compensation cost related to non-vested awards not yet recognized was approximately $616,723 as of December 31, 2006 and the weighted average period over which this cost will be recognized is approximately 9 months.

Recently Issued Pronouncements

In July 2006, the FASB issued Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109, which seeks to reduce the diversity in practice associated with the accounting and reporting for uncertainty in income tax positions. This Interpretation prescribes a comprehensive model for the financial statement recognition, measurement, presentation and disclosure of uncertain tax positions taken or expected to be taken in income tax returns. FIN 48 is effective for fiscal years beginning after December 15, 2006 and the Company will adopt the new requirements in its fiscal first quarter of 2007. The Company does not expect the adoption of this statement in fiscal year 2007 to have a material impact on the Company s financial position or results of operations.

In September 2006, the FASB issued Statement of Financial Accounting Standards (SFAS) 157, Fair Value Measurements (SFAS 157) , which provides guidance on measuring the fair value of assets and liabilities. SFAS 157 will apply to other accounting pronouncements that require or permit assets or liabilities to be measured at fair value but does not expand the use of fair value to any new circumstances. This standard will also require additional disclosures in both annual and quarterly reports. SFAS 157 will be effective for financial statements issued for fiscal years beginning after November 15, 2007. The Company is currently determining the effect, if any, the adoption of SFAS 157 will have on its financial statements.

In September 2006, the SEC staff issued Staff Accounting Bulletin No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements (SAB 108). The intent of SAB 108 is to reduce diversity in practice for the method companies use to quantify financial statement misstatements, including the effect of prior year uncorrected errors. SAB 108 establishes an approach that requires quantification of financial statement errors using both an income statement and a cumulative balance sheet approach. SAB 108 is effective for fiscal years beginning after November 15, 2006, and the Company will adopt the new requirements in fiscal 2008. The adoption of SAB 108 is not currently expected to have a significant impact on the Company s consolidated financial statements.

NOTE 3 BUSINESS COMBINATIONS

Tethys Petroleum Limited

On June 7, 2005, CanArgo made an offer to acquire 55% of the ordinary share capital of Tethys Petroleum Investments Limited, now known as Tethys Petroleum Limited, (Tethys) which was held by Provincial Securities Limited (Provincial) and Vando International Finance Limited (Vando) for consideration of 11,000,000 CanArgo common shares. On June 9, 2005 CanArgo issued 5,500,000 shares to Provincial, of which Russell Hammond (one of our non-executive directors) is Investment Advisor and 5,500,000 shares to Vando in connection with this transaction. At June 7, 2005, the closing price of CanArgo total common stock was $0.76 giving the common stock consideration a market value of $8,360,000 for the 11 million shares. On completion of the acquisition, CanArgo held 100% of the ordinary share capital of Tethys through its subsidiary CanArgo Limited and Tethys became a wholly-owned subsidiary of the Company. We have recorded our interest as if the acquisition occurred on June 30, 2005. Tethys primary asset was its 70% interest in BN Munai, a Kazakhstan limited partnership.

The purchase price was allocated to the net assets of Tethys as follows:

Cash	$ 609,553
Oil and Gas Properties	6,418,115
Other Current Assets	1,688,294
Current Liabilities	(297,162)
Provision for future site restoration	(58,800)
	$ 8,360,000

The principal reason for the purchase was to secure Tethys current interests in a proven gas field and significant exploration areas in western Kazakhstan.

The Company has included the results of operations of Tethys in the consolidated financial statements starting July 1, 2005.

The following pro forma presentation assumes the Company s acquisition of Tethys took place on January 1, 2004. The historical column presents the financial information of the Company for the periods indicated.

	Pro Forma Twelve Months Ended December 31, 2005			
	Historical	Tethys	Adjustments	Combined
Revenue	$ 5,278,912	$ 0	$	$ 5,278,912
Loss from continiung operations	(12,938,484)	($215,649)	$ 155,016(1)	(12,999,117)
Net (loss)	($12,335,314)	($215,649)	$ 155,016	($12,395,947)
Basic and diluted loss per share				($0.06)
Basic and diluted weighted average common shares outstanding				211,586,593

(1) To add back the equity loss on investment recorded during the first six months of 2005 for the Company s share of losses prior to acquisition of its majority interst.

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	Pro Forma Twelve Months Ended December 31, 2004			
	Historical	Tethys	Adjustments	Combined
Revenue	$ 7,832,894	$ 0	$	$ 7,832,894
Loss from continiung operations	($6,261,501)	$ 0	$ 0	($6,261,501)
Net (loss)	($4,757,494)	$ 0	$ 0	($4,757,494)
Basic and diluted income per share				($0.04)
Basic and diluted weighted average common shares outstanding				134,005,390

NOTE 4 RESTRICTED CASH

Restricted cash consisted of the following at December 31:

		2006	2005
Restricted Cash	Secured deposits	$ 299,777	$ 3,181,672
		$ 299,777	$ 3,181,672

In the first quarter of 2005 we funded a certificate of deposit in the amount of $3,900,000 to secure the issuance of a letter of credit as required under the rig rental and drilling contract we entered into with Saipem, S.p.A. Under the terms of the letter of credit $1,100,000 was released and became unrestricted cash in July 2005. The remaining deposit became unrestricted during 2006.

In the third quarter of 2005, we deposited approximately $300,000 to secure the issuance of a letter of credit as required under the drilling contract we entered into with Baker Hughes International and which remains at December 31, 2006.

NOTE 5 ACCOUNTS RECEIVABLE

Accounts receivable consisted of the following at December 31:

	2006	2005
Trade receivables before allowance for doubtful debts	$	$ 919,512
Allowance for doubtful debts		(910,047)
Insurance receivable	474,665	31,755
Fees due from underwriters		180,000
Other receivables	34,658	191,963
	$ 509,323	$ 413,183
Non Current Assets		
Other receivables	$ 1,086,350	$

	$ 1,086,350	$

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Bad debt expense for 2006, 2005 and 2004 was nil, $145,829 and $5,803 respectively, and is reflected under other income in the statement of operations.

In the second quarter of 2006 we filed a claim with our insurance carrier for recovery of drilling equipment lost in the Manavi 12 well. As of December 31, 2006, $474,665 was recorded as a receivable in connection with this claim. This claim was settled in full by our insurance carrier in February 2007.

In September 2004, a blow-out occurred at the N100 well on the Ninotsminda Field. Our insurers will cover 80% of the costs associated with the blow out up to a maximum cover of $2,500,000. We received $800,000 from our insurers in the second quarter of 2005 in respect of costs incurred to date. As of December 31, 2005 $31,755 was recorded as a receivable. No amounts have been recorded as a receivable re the blow-out as of December 31, 2006.

Non current asset accounts receivables of $1,086,350 at December 31, 2006 relate to VAT amounts recoverable from our Kazakhstan operations as an offset against VAT payable on future gas revenues.

NOTE 6 INVENTORY

Inventory of crude oil consisted of the following at December 31:

	2006	2005
Crude oil	$ 452,500	$ 886,250
	$ 452,500	$ 886,250

NOTE 7 PREPAYMENTS

Prepayments consisted of the following at December 31:

	2006	2005
Drilling Contractors	$ 5,954,204	$ 4,053,471
Financing Fees	201,526	115,158
Other	287,687	207,226
	$ 6,443,417	$ 4,375,855

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NOTE 8 CAPITAL ASSETS

Capital assets, net of accumulated depletion, depreciation and amortization (DD&A) and impairment, include the following at December 31, 2006:

	Cost	Accumulated DD&A And Impairment	Net Capital Assets
Oil and Gas Properties			
Proved properties	$ 101,261,686	$ (67,608,087)	$ 33,653,599
Unproved properties	68,313,162		68,313,162
	169,574,848	(67,608,087)	101,966,761
Property and Equipment			
Oil and gas related equipment	13,474,127	(5,598,712)	7,875,415
Office furniture, fixtures and equipment and other	1,365,274	(661,468)	703,806
	14,839,401	(6,260,180)	8,579,221
	$ 184,414,249	$ (73,808,267)	$ 110,545,982

Capital assets, net of accumulated depletion, depreciation and amortization and impairment (DD&A), include the following at December 31, 2005:

	Cost	Accumulated DD&A And Impairment	Net Capital Assets
Oil and Gas Properties			
Proved properties	$ 83,451,848	$ (26,033,501)	$ 57,418,347
Unproved properties	50,644,999		50,644,999
	134,096,847	(26,033,501)	108,063,346
Property and Equipment			
Oil and gas related equipment	15,453,405	(5,146,040)	10,307,365
Office furniture, fixtures and equipment and other	1,135,601	(458,263)	677,338
	16,589,006	(5,604,303)	10,984,703
	$ 150,685,853	$ (31,637,804)	$ 119,048,049

We expensed $3,831,472, $3,275,553 and $2,881,020 in respect of depletion, depreciation and amortization for the years ended December 31, 2006, 2005 and 2004, respectively.

Depletion per Barrel of Oil Equivalent on a Units of Production basis was $3,174,586 ($45.57), $2,651,053 ($18.67) and $2,298,218 ($8.45) for the years ended December 31, 2006, 2005 and 2004, respectively. All production in the periods presented related to Georgia. Production from our Samgori Field attracted depletion from the date of acquisition in April 2004 to December 31, 2005. Production from our Ninotsminda Field attracted depletion for all years presented.

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During the period we transferred approximately $7,900,000 of capital asset costs, into the full cost pool from unproved properties, relating to an abandonment of part of the Norio MK72 well and a 25% field acreage relinquishment of the Norio Production Sharing Agreement.

Oil and Gas Properties

Ultimate realization of the carrying value of our oil and gas properties will require production of oil and gas in sufficient quantities and marketing such oil and gas at sufficient prices to provide positive cash flow to CanArgo, which is dependent upon, among other factors, achieving significant production at costs that provide acceptable margins, reasonable levels of taxation from local authorities, and the ability to market the oil and gas produced at or near world prices. In addition, we must mobilize drilling equipment and personnel to initiate drilling, completion and production activities. If one or more of the above factors, or other factors, are different than anticipated, we may not recover our carrying value.

As a result of application of the ceiling test limitation, CanArgo recorded a write-down of oil and gas properties, relating to Georgia, of $38,400,000 in 2006. In 2005 and 2004, CanArgo did not need to write-down oil and gas properties due to the ceiling test.

We generally have the principal responsibility for arranging financing for the oil and gas properties and ventures in which we have an interest. There can be no assurance, however, that we or the entities that are developing the oil and gas properties and ventures will be able to arrange the financing necessary to develop the projects being undertaken or to support our corporate and other activities or that such financing as is available will be on terms that are attractive or acceptable to or are deemed to be in the best interests of the Company, such entities or their respective stockholders or participants.

The consolidated financial statements of CanArgo do not give effect to any additional impairment in the value of our investment in oil and gas properties and ventures or other adjustments that would be necessary if financing cannot be arranged for the development of such properties and ventures or if they are unable to achieve profitable operations. Failure to arrange such financing on reasonable terms or failure of such properties and ventures to achieve profitability would have a material adverse effect on our financial position, including realization of assets, results of operations, cash flows and prospects.

Unproved property additions relate to our exploration activity in the period.

We plan to test a substantial portion of our unproved properties for oil and gas in 2007. In the event that we do not find oil and gas, we could incur substantial impairments were the amounts to exceed our ceiling test.

Costs Not Being Amortised

Oil and gas property costs not being amortized at December 31, 2006, for both Georgia and Kazakhastan by year that the costs were incurred are as follows:

Year Ended December 31:	Exploration	Acquisition	Total Capital
2006	$ 18,860,161	$ (1,191,998)	$ 17,668,163
2005	16,133,409	9,408,644	25,542,054
2004	5,282,204		5,282,204
Prior	15,103,096	4,717,646	19,820,741
	$ 55,378,870	$ 12,934,292	$ 68,313,162

Unevaluated costs include $41,271,824 for the Ninotsminda Field. $2,000,000 was allocated to the Cretaceous on acquisition prior to 2003. The structure named Manavi was proved to contain oil and gas by an original exploration well in 2003. This well was sidetracked in 2005 as M11Z and now awaits testing. Another appraisal well, M12, was drilled in 2006 and now awaits further testing. The M12 well also encountered hydrocarbons and we plan to test this well in Spring 2007 when we import special chemicals to Georgia. Following a successful test of M12, we plan to proceed with testing the M11Z well.

Unevaluated costs include $9,798,615 for the Norio Field. An exploration well was completed at the end of 2005 and discovered hydrocarbons in the two objective zones in the well. The shallow zone in the well was subsequently tested, but did not flow oil and gas at commercial rates due to what we suspect to be reservoir damage caused by the drilling fluids used to drill the well. We were unable to test the deeper zone which was the primary target in the well due to operational constraints. Consequently, in order to properly evaluate these discoveries, we plan to side track this well once we have a rig with deep drilling capability and financing available. The results of a sidetrack appraisal well will determine whether further appraisal or development drilling is required.

Unevaluated costs include $4,026,660 for the Nazvrevi Field. $2,695,145 was allocated to the Field on acquisition prior to 2003. It also includes the significant Kumisi Cretaceous gas where we commenced drilling in February 2007. We expect to complete this well during the Summer of 2007 after which time we will determine whether further appraisal or development drilling is required.

Unevaluated costs include $13,216,063 for Tethys. $9,408,644 was allocated to unevaluated areas on acquisition in 2005.In Kazakhstan, we are in the process of completing an exploration program. Current plans are to undertake further exploration drilling in 2007.

Property and Equipment

Property and Equipment, Oil and gas related equipment includes related equipment currently in use by us in the development of the Ninotsminda Field.

NOTE 9 INVESTMENTS

Investments at December 31:

	2006	2005
Cash on deposit	$ 205,484	$
	$ 205,484	$

Investments at December 31, 2006 consisted of bank deposits with maturity dates of April 27, 2008 and December 28, 2008. These deposits have been placed to satisfy local Kazakhstan requirements in respect of asset retirement obligations.

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NOTE 10 PREPAID FINANCING FEES

Prepaid financing fees at December 31:

	2006	2005
Commission and Professional fees	$ 318,632	$ 246,910
	$ 318,632	$ 246,910

Prepaid financing fees as at December 31, 2006 are corporate finance fees incurred in respect of the private placement of a $25,000,000 issue of Senior Convertible Secured Notes due July 25, 2009, a $13,000,000 issue of Senior Subordinated Convertible Guaranteed Notes due September 1, 2009, a $10,000,000 issue of a 12% Subordinated Convertible Guaranteed Note due June 28, 2010 and a $5,000,000 issue of Senior Secured Notes by CanArgo s wholly owned subsidiary Tethys, with a group of investors, discussed in Note 12 and which are to be amortized as interest expense over the term of the loans. Professional fees of $147,343 were amortized on a straight-line basis in 2006 in connection with the Notes.

Prepaid financing fees as at December 31, 2005 are corporate finance fees incurred in respect of the private placement of a $25,000,000 issue of Senior Convertible Secured Notes due July 25, 2009. Professional fees of $42,312 were amortized to interest expense on a straight-line basis in 2005 in connection with the Senior Secured Notes.

NOTE 11 LOANS PAYABLE AND LONG TERM DEBT

Loans payable at December 31 consisted of the following:

	2006	2005
Short term loans payable		
Promissory Notes	$	$
Loan with detachable warrants		1,050,000
Unamortized debt discount		(85,858)
Loans payable	$	$ 964,142
Long term debt		
Senior Secured Convertible Loan Notes	$ 25,000,000	$ 25,000,000
Senior Subordinated Convertible Guaranteed Loan Notes	13,000,000	
12% Subordinated Convertible Guaranteed Loan Note	10,000,000	
Tethys Senior Secured Notes	5,000,000	
Unamortized debt discount	(12,652,057)	
Long term debt	$ 40,347,943	$ 25,000,000

The maturities of long-term borrowings at December 31, 2006, was as follows:

	2007	2008	2009	2010	2011
Repayments due	$	$ 5,000,000	$ 38,000,000	$ 10,000,000	$

	$	$ 5,000,000	$ 38,000,000	$ 10,000,000	$

In order to ensure timely procurement of long lead items for our drilling programs in Georgia and Kazakhstan and for working capital purposes, we have entered into a number of loan agreements of which those outstanding during 2006 are described below.

Loan with Detachable Warrants: This loan, the balance of which was $1,050,000 at date of conversion, from Salahi Ozturk was advanced pursuant to the amended and restated loan and warrant agreement dated August 27, 2004. On February 14, 2006 we exercised the option forcing conversion of the loan into 1,521,739 shares of our common stock.

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On May 19, 2004, we signed a promissory note with Cornell Capital Partners, L.P. (Cornell Capital) whereby Cornell Capital agreed to advance us the sum of $1,500,000. We have repaid the promissory note by making a series of takedowns in February and March 2005 under the Standby Equity Distribution Agreement.

On April 26, 2005 we signed a promissory note with Cornell Capital whereby Cornell Capital agreed to advance us the sum of $15 million (Promissory Note) under the following terms:

This $15 million and interest at a rate of 7.5% per annum was payable either in cash or using the net proceeds of drawdowns under the SEDA, within 270 calendar days from the date of the Promissory Note. Pursuant to the terms of the Promissory Note, we escrowed 25 requests for advances under the SEDA each in an amount not less than $600,000 and one advance of $289,726.03 (representing estimated interest) together with 16,273,592 shares of CanArgo common stock, as at the agreement date, 664,966 shares were already in escrow.

The Promissory Note was repaid in full in cash on August 1, 2005, all escrowed advances cancelled and 7,260,647 shares of CanArgo common stock were returned from escrow and duly cancelled on October 5, 2005. On July 25, 2005 notice was given to Cornell Capital to terminate the SEDA with effect as of August 24, 2005.

Senior Secured Convertible Notes: On July 25, 2005, CanArgo completed a private placement of $25,000,000 in aggregate principal amount of our Senior Convertible Secured Loan Notes due July 25, 2009 (the Senior Secured Notes) with a group of private investors (the Purchasers) all of which qualified as accredited investors under Rule 501(a) promulgated under the Securities Act of 1933 as amended, (the Securities Act) arranged through Ingalls & Snyder LLC of New York City, as Placement Agent, pursuant to a Note Purchase Agreement of even date (the Senior Note Purchase Agreement). The Company paid approximately $100,000 of legal fees for the Purchasers and a $250,000 arrangement fee to Orion Securities in connection with the Senior Secured Notes.

The unpaid principal balance under the Senior Secured Notes bears interest (computed on the basis of a 360 day year of twelve 30-day months) (a) at increasing rates ranging from 3% from the date of issuance to December 31, 2005; 10% from January 1, 2006 until December 31, 2006; and 15% from January 1, 2007 until final payment, payable semi-annually, on June 30 and December 30, commencing December 30, 2005, until the principal shall have become due and payable, and (b) at 3% above the applicable rate on any overdue payments of principal and interest,

Pursuant to the provisions of Emerging Issue Task Force 86-15: Increasing-Rate Debt , the Company recognizes interest expense using the effective interest rate method, which results in the use of a constant interest rate for the life of the Senior Secured Notes. The effective interest rate is approximately 12.3% per annum. The difference between the interest computed using the actual interest rate in effect (3% per annum to December 31, 2005 and 10% from January 1, 2006) and the effective interest rate (12.3% per annum) was $1,576,041 as of

December 31, 2006 of which $675,000 has been included in accrued liabilities and $901,041 has been accrued as a non-current liability.

The Company is amortising the professional fees incurred in relation to the Senior Secured Notes over the term of the Senior Secured Notes.

The Senior Secured Notes are convertible any time, in whole or in part, at the option of the Note holder, into shares of CanArgo common stock (the Conversion Stock) which is subject to (a) customary anti-dilution adjustments and (b) adjustment if CanArgo issues any equity securities (other than pursuant to the granting of employee stock options pursuant to shareholder approved employee stock option plans or existing outstanding options, warrants and convertible securities), at a price per share of less than $0.90 per share, as adjusted (the CanArgo Conversion Price), determined net of all discounts, fees, costs and expenses incurred in connection with such issuance, in which case the CanArgo Conversion Price will be reset to such lower price.

We may, at our option without the consent of Note holders, upon not less than 90 days and not more than 120 days prior written notice, prepay at any time and from time to time after July 31, 2006, all or any part of the Senior Secured Notes, in a principal amount of not less than $100,000 at the following Redemption Prices (expressed as percentages of the principal amount so prepaid): 105% after July 31, 2006; 104% after January 1, 2007; 103% after July 1, 2007; 102% after January 1, 2008; 101% after July 1, 2008, and 100% after January 1, 2009, together with all accrued and unpaid interest.

The Senior Secured Notes are subject to mandatory prepayment due to a change in control of the Company, as defined by the Senior Note Purchase Agreement.

In connection with the execution and delivery of the Senior Note Purchase Agreement, CanArgo entered into a Registration Rights Agreement with the Purchasers pursuant to which it agreed to register the Conversion Stock for resale under the Securities Act and indemnify the purchasers in connection with the registration. Under the terms of a Registration Rights Agreement the Company provided the Purchasers with certain registration rights with respect to the Conversion Stock. The Conversion Stock was registered on a Registration Statement on Form S-1 which was declared effective by the SEC on January 30, 2006.

The Senior Secured Notes are secured by substantially all of the assets of the Company and its subsidiaries and contain certain negative and affirmative covenants and also restricts the ability of the Company to pay dividends to its common stockholders until the loan and all accrued interest have been paid or the Note holders elect to convert their loans to common stock. (See page 35 Liquidity and Capital Resources section of Item 2 below for a more detailed discussion of covenants).

The Company evaluated the embedded conversion feature in this debt and determined it did not meet the criteria for bifurcation under SFAS No 133 Accounting for Derivative Instruments and Hedging Activities during the quarter.

Senior Subordinated Convertible Guaranteed Notes: On March 3, 2006, we finalised a private placement with a limited group of investors arranged by Ingalls & Snyder LLC of New York City of a $13,000,000 issue of Senior Subordinated Convertible Guaranteed Notes due September 1, 2009 (the Senior Subordinated Notes) and warrants to purchase an aggregate of 13,000,000 shares of our common stock, par value $0.10 per share (Warrant Shares) at an exercise price of $1.37 per share, subject to adjustment as defined below, and expiring on March 3, 2008 or sooner under certain circumstances (Warrants).

The proceeds of this financing, after the payment of all placing expenses and professional fees estimated at $150,000, are being used to fund the development of the Kyzyloi Gas Field in Kazakhstan and on the commitment exploration programs in Kazakhstan through Tethys Petroleum Limited (Tethys), the wholly owned subsidiary of CanArgo which holds CanArgo s Kazakhstan assets.

Pursuant to the provisions of Emerging Issue Task Force 86-15: Increasing-Rate Debt , the Company recognizes interest expense using the effective interest rate method, which results in the use of a constant interest rate for the life of the Senior Subordinated Notes. The effective interest rate is approximately 8.3% per annum. The difference between the interest computed using the actual interest rate in effect (3% per annum to December

31, 2006 and 10% from January 1, 2007) and the effective interest rate (8.3% per annum) was $574,839 as of December 31, 2006 of which $215,800 has been included as an accrued liability and $359,039 has been accrued as a non-current liability.

We entered into a Note and Warrant Purchase Agreement dated as of March 3, 2006 (Senior Subordinated Note Purchase Agreement) with a limited group of private investors (the Purchasers) all of whom qualified as accredited investors under Rule 501(a) promulgated under the Securities Act. Pursuant to the Note Purchase Agreement, we issued the Senior Subordinated Notes, one of which was issued to Ingalls & Snyder LLC as nominee for certain Purchasers, and the Warrants, one of which was also issued to Ingalls & Snyder LLC as nominee for certain Purchasers, in a transaction intended to qualify for an exemption from registration under the Securities Act pursuant to Section 4(2) thereof and Regulation D promulgated thereunder. For purposes hereof each of the Purchasers for whom Ingalls & Snyder LLC acts as nominee is deemed a beneficial holder of the Senior Subordinated Note and Warrant issued in Ingalls & Snyder LLC s name and such Purchasers may each be assigned their own Senior Subordinated Note and Warrant as provided in the Senior Subordinated Note Purchase Agreement.

The principal terms of the Senior Subordinated Note Purchase Agreement and related agreements include the following:

Interest. The unpaid principal balance under the Senior Subordinated Notes bears interest (computed on the basis of a 360-day year of twelve 30-day months) payable semi-annually on June 30 and December 30 in cash at the rate of 3% per annum until December 31, 2006 and 10% per annum thereafter and (b) at the rate of 3% per annum above the applicable rate on any overdue payments of principal and interest.

Optional Prepayments. CanArgo may, at its option, upon at least not less than 60 days and not more than 120 days prior written notice, prepay at any time and from time to time after March 1, 2007, all or any part of the Senior Subordinated Notes, in a principal amount of not less than $100,000 at the following Redemption Prices (expressed as percentages of the principal amount so prepaid): 105% after March 1, 2007; 104% after September 1, 2007; 103% after March 1, 2008; 102% after September 1, 2008; 101% after March 1, 2009, and 100% after September 1, 2009, together with all accrued and unpaid interest.

Mandatory Prepayment. CanArgo will not take any action to consummate a Change of Control (or Change of Control contemplated by a Control Event) unless it shall offer to prepay all, but not less than all, of the Senior Subordinated Notes, on not less than 15 business days prior written notice, in the event of an occurrence of a Change of Control or Control Event. Mandatory prepayment of the Senior Subordinated Notes shall be in an amount equal to 101% of the outstanding principal amount of such Senior Subordinated Notes, together with interest on such Senior Subordinated Notes accrued to the date of prepayment. *Change in Control* is defined to mean (a) if CanArgo shall at any time cease to be a publicly held company or cease to have its capital stock traded on an exchange or (b) a transaction or series of related transactions pursuant to which (i) at least fifty-one percent (51%) of the outstanding shares of CanArgo s common stock or, on a fully diluted basis, shall subsequent to March 3, 2006 be owned by any person which is not related to or affiliated with CanArgo, (ii) if CanArgo merges into or with, consolidates with or effects any plan of share exchange or other combination with any person which is not related to or affiliated with CanArgo, or (iii) if CanArgo disposes of all or substantially all of its assets other than in the ordinary course of business and *Control Event* is defined to mean (i) the execution by CanArgo or any material subsidiary of CanArgo which has guaranteed the indebtedness evidenced by the Senior Subordinated Notes (a CanArgo Group Member) of any agreement or letter of intent with respect to any proposed transaction or event or series of transactions or events which, individually or in the aggregate, may reasonably be expected to result in a Change in Control, or (ii) the execution of any written agreement which, when fully performed by the parties thereto, would result in a Change in Control.

Conversion. The Senior Subordinated Notes are convertible, in whole or in part, (A) into shares of CanArgo common stock (CanArgo Conversion Stock) at a conversion price per share of $1.37 (the CanArgo Conversion Price), which is subject to adjustment if CanArgo issues any equity securities (other than pursuant to the granting of employee stock options pursuant to shareholder approved employee stock option plans or existing outstanding options, warrants and convertible securities, including, without limitation, the Company s Senior Secured Notes) at a price per share of less than $1.37 per share, as adjusted, determined net of all discounts, fees, costs and expenses incurred in connection with such issuance, in which case the CanArgo Conversion Price will be reset to such lower price and (B) for a period of one year from closing (or until 30 days after receipt of the consent of the Senior Secured Note holders is obtained if such conversion is prevented under the terms of the Senior Secured Notes) into shares of common stock of Tethys, with a nominal value of £0.10 per share (Tethys Conversion Stock and together with the CanArgo Conversion Stock, collectively, the Conversion Stock) at a conversion price per share based on a formula determined by dividing the sum of $52 million plus the amount of any unreimbursed amounts advanced by the Company to Tethys by 100,000 (Tethys Conversion Price and together with the CanArgo Conversion Price, collectively, the Conversion Price) in the Note holders Relevant Percentages (as defined in the Senior Subordinated Note Purchase Agreement). The Conversion Price shall also be adjusted in connection with any stock split, stock dividend, reverse stock split, reclassification, recapitalization, combination, merger, consolidation or any similar transaction, in which case the Conversion Price and number of shares of Conversion Stock will be appropriately adjusted to reflect any such event, such that the holders of the Senior Subordinated Notes will receive upon conversion the identical number of shares of common stock or other consideration or property to be received by the holders of the common stock as if the holders had converted the Senior Subordinated Notes immediately prior to any such event as such amount would then be adjusted by reason of such stock split, stock dividend, reverse stock split, reclassification, recapitalization, combination, merger, consolidation or other similar transaction; provided, however, in no event shall the number of shares of common stock issuable to the Purchasers upon conversion cause the Purchasers to collectively own in excess of 19.9% of the shares of CanArgo common stock outstanding as of March 3, 2006 absent shareholder approval in accordance with applicable stock exchange requirements. No fractional shares of common stock shall be issued upon any conversion; instead the Conversion Price shall be appropriately adjusted so that holders shall receive the nearest whole number of shares upon any conversion.

In connection with the execution and delivery of the Senior Subordinated Note Purchase Agreement, CanArgo entered into a Registration Rights Agreement with the Purchasers pursuant to which it agreed to register the CanArgo Conversion Stock and the Warrant Shares for resale under the Securities Act. Pursuant to the terms of the Registration Rights Agreement the Company provided the Purchasers with certain registration rights with respect to all shares of the Company s common stock issuable upon conversion of the Senior Subordinated Notes and all shares of the Company s common stock issuable upon exercise of the Warrants. The Company has not provided the Purchasers with any registration rights in relation to the Tethys Conversion Stock. Under the Registration Rights Agreement the Company has agreed to use all commercially reasonable efforts to file a Registration Statement on Form S-3 or Form S-1 in respect of the CanArgo Conversion Stock by December 31, 2006.

Security. Payment of all amounts due and payable under the Senior Subordinated Note Purchase Agreement, the Senior Subordinated Note and all related agreements (collectively, the Loan Documents) is secured by subordinated guarantees from each other CanArgo Group Member (the Subordinated Subsidiary Guaranty). If CanArgo forms or acquires a Material Subsidiary (as defined in the Senior Subordinated Note Purchase Agreement) it shall cause such Subsidiary to execute a Subordinated Subsidiary Guaranty (other than for certain excepted companies and legal entities) and thereby become a CanArgo Group Member subject to the provisions of the Senior Subordinated Note Purchase Agreement.

Subordination. Payments on the Senior Subordinated Notes and under the Subordinated Subsidiary Guaranty are subordinated and junior in right of payment to the prior payment or conversion in full of CanArgo s Senior Indebtedness in the event of the bankruptcy, insolvency or other reorganization of CanArgo. Under the terms of the subordination, holders of the Senior Subordinated Notes agree for the benefit of the holders of the Senior Indebtedness to certain limitations on their right to accelerate or demand payment under the Senior Subordinated Notes or otherwise realize under the Subordinated Subsidiary Guaranty in the event of a default under the Senior Indebtedness. *Senior Indebtedness* is defined to mean (i) all indebtedness under the Senior Secured Notes or any related agreements; (ii) certain permitted indebtedness now existing or hereafter arising, and (iii) all renewals, refinancings, extensions, modifications and replacements of any of the foregoing.

Covenants. Under the terms of the Senior Subordinated Note Purchase Agreement CanArgo is subject to certain affirmative and negative covenants, which can be waived by the beneficial holders of at least 50% of the outstanding principal amount of the Senior Subordinated Notes (the Required Holders), including the following affirmative and negative covenants, respectively: (a) providing current information regarding CanArgo and rights of inspection;

compliance with laws; maintenance of corporate existence, insurance and properties; payment of taxes; adding new material subsidiaries as additional guarantors under the Subordinated

Subsidiary Guaranty; payment of professional fees for the Purchasers (not in excess of US$75,000), and (b) restrictions on: transactions with affiliates; mergers, consolidations and sales of all of CanArgo s assets; liens (except for certain permitted liens); the issuance of additional senior indebtedness; changes in CanArgo s line of business; certain types of payments; sale-and leasebacks; sales of assets other than in the ordinary course of business; future Indebtedness, as defined in the Senior Subordinated Note Purchase Agreement (other than certain permitted indebtedness); cancelling, terminating, waiving or amending provisions of, or selling any interests in (other than under certain circumstances) any of the Basic Agreements (as defined in the Senior Subordinated Note Purchase Agreement); adopting any anti-take-over defences except as permitted by the Senior Subordinated Note Purchase Agreement, and restricting distributions of Tethys cash flow to CanArgo except for certain reimbursements of payments made by CanArgo on Tethys behalf, or in respect of management fees and overhead not to exceed $100,000 per month. CanArgo is not subject to any financial covenants, such as the maintenance of minimum net worth or coverage ratios, other than the restriction on its ability to incur additional Indebtedness.

Events of Default. An Event of Default shall exist if one or more of the following occurs and is continuing: (i) failure to pay when due any principal and, after 5 business days, any interest, payable under the Senior Subordinated Note or any Loan Document; (ii) default in the performance of certain enumerated covenants; (iii) default in the performance or compliance with any other terms which remains unremedied for 30 days after the earlier of a Responsible Officer first obtaining actual and not constructive knowledge of the default or the receipt of notice; (iv) any representation or warranty made in writing on behalf of CanArgo or any other CanArgo Group Member proves to have been false or incorrect in any material respect; (v) customary events involving bankruptcy, insolvency or reorganization; (vi) the entry of a final judgment or judgments in excess of $2,500,000 (uncovered by insurance), which is not discharged or settled; (vii) violations of ERISA or the Internal Revenue Code of 1986, as amended, under funding of accrued benefit liabilities and other matters relating to employee benefit plans subject to ERISA or Foreign Pension Plans; (viii) any Loan Document ceases to be in full force and effect (except in accordance with its terms) or its validity is challenged by CanArgo or any affiliate; (ix) CanArgo or any other CanArgo Group Member modifies its Charter Document which results in a Default or Event of Default or will adversely affect the rights of Note holders (other than for an increase in the number of authorized shares of the Company s common stock from 300 million to 375 million shares); or (x) a change occurs in the consolidated financial condition of CanArgo or in the physical, operational or financial status of the Properties (as defined in the Senior Subordinated Note Purchase Agreement), which change has a Material Adverse Effect (as defined in the Senior Subordinated Note Purchase Agreement).

Other than for certain Events of Default that will result in an automatic acceleration without notice, such as bankruptcy, if an Event of Default occurs and is continuing, the Required Holders may at any time at its or their option, by notice to CanArgo, declare all outstanding Senior Subordinated Notes to be immediately due and payable and holders of the Senior Subordinated Note may proceed to enforce their rights under the Loan Documents at law or in equity. CanArgo is responsible for the payment of all costs of collection, including all reasonable legal fees actually incurred in connection therewith.

Warrants. The Warrants expire on March 3, 2008 or such sooner date at the election of the Company and upon at least 30 days prior written notice in the event that the Manavi M12 well indicates, by an independent engineering report, sustainable production, if developed, in excess of 7,500 barrels of oil per day, and are exercisable at an exercise price of $1.37 per share (Exercise Price), subject to adjustment in connection with any stock split, stock dividend, reverse stock split, reclassification, recapitalization, combination, merger, consolidation or any similar transaction, in which case the Exercise Price and number of Warrant Shares will be appropriately adjusted to reflect any such event, such that the holders of the Warrants will receive upon exercise the identical number of shares of common stock or other consideration or property to be received by the holders of the common stock as if the holders had exercised the Warrants immediately prior to any such event as such amount would then be adjusted by reason of such stock split, stock dividend, reverse stock split, reclassification, recapitalization, combination, merger, consolidation or other similar transaction. If CanArgo issues any equity securities (other than pursuant to the granting of employee stock options pursuant to shareholder approved employee stock option plans or existing outstanding options, warrants and convertible securities, including, without limitation, the conversion of the Senior Secured Notes) at a price per share of less than $1.37 per share, as adjusted, determined net of all discounts, fees, costs and expenses incurred in connection with such issuance, the Exercise Price will be reset to such lower price; provided, however, in no event shall the number of Warrant Shares issuable upon exercise cause Warrant holders to collectively own in excess of 19.9% of the shares of

CanArgo common stock outstanding as of March 3, 2006 absent shareholder approval in accordance with applicable stock exchange requirements. No fractional shares of common stock shall be issued upon any exercise; instead the Exercise Price shall be appropriately adjusted so that holders shall receive the nearest whole number of shares upon any conversion.

Miscellaneous. The execution of the Senior Subordinated Note Purchase Agreement was conditional upon the consent, which was obtained, from 51% of the holders of the Senior Secured Notes pursuant to a Waiver, Consent and Amendment dated as of March 3, 2006 (Waiver, Consent and Amendment Agreement). Under the terms of the Waiver, Consent and Amendment Agreement, the holders of the Senior Secured Notes further consented to certain amendments to the Note Purchase Agreement dated July 25, 2005 among the Company and Ingalls & Snyder Value Partners, L.P together with the other purchasers listed therein to provide for the amendment or termination of the Company s or any of the Subsidiaries interests in the Production Sharing Contract dated May 2001 among the State Agency of Georgia, Georgian Oil and National Petroleum Limited (the Samgori PSC), a Basic Document as defined in the Senior Note Purchase Agreement, including without limitation, a waiver of the negative covenants set forth in Section 11.10 of the Senior Note Purchase Agreement and an increase in the authorized capital stock of the Company to 380 million shares of which 375 million shares shall constitute common stock and 5 million shares shall constitute preferred stock. The Senior Subordinated Note Purchase Agreement, the Senior Subordinated Note, the Subordinated Subsidiary Guaranty and the Registration Rights Agreement are all governed by New York Law and the Warrants are governed by the laws of the State of Delaware; the CanArgo Group Members party thereto subject themselves to the jurisdiction of New York Courts and waive the right to jury trial.

The Company evaluated the embedded conversion feature in this debt and determined it does meet the criteria for bifurcation under SFAS No 133 Accounting for Derivative Instruments and Hedging Activities during the quarter.

Pursuant to EITF 98-5 Accounting for Convertible Securities with Beneficial Conversion Features or Contingently Adjustable Conversion Ratios and EITF 00-27 Application of Issue No. 98-5 to Certain Convertible Instruments , the Company had initially recorded a discount to the Senior Subordinated Note in the amount of approximately $6,483,000 based on the relative fair value of the beneficial conversion feature and warrants of $2,245,000 and $4,238,000, respectively.

We used the following assumptions to determine the fair value of the Senior Subordinated Notes and Warrants:

	Additional Loan
Stock price on date of grant	$ 1.16
Risk free rate of interest	4.72%
Expected life of warrant months	24
Dividend rate	
Historical volatility	68.6%

On June 28, 2006, we announced that we had entered into the private placement with Persistency, a Cayman Islands company, of a $10,000,000 issue of a 12% Subordinated Convertible Guaranteed Note due June 28, 2010 (see 12% Subordinated Convertible Guaranteed Note below) and warrants to purchase an aggregate of 12,500,000 shares of CanArgo common stock (Warrant Shares), at an exercise price of $1.00 per share, subject to adjustment, and expiring on June 28, 2008 or sooner under certain circumstances (the 12% Note Warrants) which is described more fully below.

As a result of entering into this private placement we issued warrants at an exercise price below $1.37 and therefore the terms of the Senior Subordinated Note Purchase Agreement and related agreements dictated that the conversion and warrant exercise prices under the Senior Subordinated Note Purchase Agreement be reset to $1.00 per share as described above.

The Company therefore recorded an additional debt discount of $3,683,000 to the Senior Subordinated Note, increasing the total debt discount to approximately $10,166,000 based on the relative fair value of the beneficial

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conversion feature and warrants of $6,123,000 and $4,043,000, respectively. Debt discount of $521,727 has been amortised to interest expense in 2006.

The Company has announced that it is planning listing the securities of Tethys on the Toronto Stock Exchange in connection with a proposed offering of Tethys shares, by Tethys and the Company (the Tethys Spin-Out), with the primary aim of raising additional capital to finance further development and exploration programs in Kazakhstan. It is currently planned that the Company will retain a significant, but not controlling, equity interest in Tethys. The Tethys Spin-Out is currently planned for later this year, dependant on market conditions, pricing etc.

In a separate transaction Persistency have arranged the acquisition of $5 million of the Senior Subordinated Notes including its conversion obligations into Tethys.

On June 28, 2006, the Company entered into a conversion agreement (Conversion Agreement) with the holders of the Senior Subordinated Notes. The Senior Subordinated Notes are to be converted within 5 days prior to the effective date of any Tethys Spin-Out. Provided that the Tethys Spin-Out is completed on a pre-money enterprise value of at least $52,000,000, the conversion price of the Senior Subordinated Notes will be in accordance with the terms of the Senior Subordinated Notes. In the event that the Tethys Spin-Out is completed on a pre-money enterprise value of less than $52,000,000, the Subordinated Noteholders shall be issued additional shares of Tethys common stock to cause the aggregate value of the Tethys common stock issued upon conversion to equal $13,000,000 at the Spin-Out price.

As an inducement for the Note holders to convert the Senior Subordinated Notes into Tethys common stock, the Company agreed to issue the Note holders 13,000,000 warrants (Compensation Warrants) to purchase CanArgo common stock at an exercise price of $1.00 per common share. We issued Compensation Warrants to purchase 5,000,000 shares on June 28, 2006 to Persistency, subject to restrictions on their right to sell, borrow against or pledge the underlying common stock until the Tethys Spin Out is effective. In addition, we entered into an irrevocable call option in which the Company has the right, but not the obligation, to repurchase the underlying common stock at $1 per share in the event that Persistency exercises its rights under the warrant and acquires our common stock and the Tethys Spin Out is never consummated. The remaining Compensation Warrants are effective upon the conversion of the Senior Subordinated Notes into Tethys common stock. All of the Compensation Warrants expire on the earlier of: (i) September 1, 2009; (ii) or such sooner date at the election of the Company and upon at least thirty (30) days prior written notice to the Registered Holder in the event that: (a) the Manavi M12 well indicates, by way of an independent engineering report, sustainable production, if developed, in excess of 7,500 barrels of oil per day or (b) all the warrants originally issued under certain Note and Warrant Purchase Agreement dated as of March 3, 2006 by and among the Company and the purchasers listed therein are exercised by the holders thereof and the average closing price for the Company s Common Stock on the American Stock Exchange or, if the Common Stock is not then listed for trading on the American Stock Exchange (AMEX) then the Oslo Stock Exchange, is above U.S. $2.00 (or its equivalent in NOK, and in any case adjusted for any stock dividends, stock split, its reverse split, recapitalization or reorganization) for a period of five consecutive trading days; or (iii) in the event the Tethys Spin-Out does not occur on or prior to December 31, 2006 (the Exercise Period). The Exercise Period may also be extended by the Company s Board of Directors.

We used the following assumptions in our Black Scholes model to determine the fair value of the Senior Subordinated Notes and Warrants:

	Additional Loan
Stock price on date of grant	$ 0.74
Risk free rate of interest	5.3%
Expected life of warrant days	1,161
Dividend rate	
Historical volatility	64.3%

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12% *Subordinated Convertible Guaranteed Note :* On June 28, 2006, we entered into a $10,000,0000 private placement with Persistency (the Purchaser) of a 12% Subordinated Convertible Guaranteed Note due June 28, 2010 (the 12% Note) and warrants to purchase an aggregate of 12,500,000 shares of CanArgo common stock (Warrant Shares), at an exercise price of $1.00 per share, subject to adjustment, and expiring on June 28, 2008 or sooner under certain circumstances (the 12% Note Warrants).

The proceeds of this financing, after the payment of all placing expenses and professional fees (estimated at $150,000), will be used to fund our appraisal and development activities in Georgia including further development of the Ninotsminda Field and potentially appraisal of the Kumisi gas discovery.

We entered into a Note and Warrant Purchase Agreement dated as of June 28, 2006 (12% Note Purchase Agreement) with the Purchaser which qualified as an accredited investor under Rule 501(a) promulgated under the Securities Act. Pursuant to the 12% Note Purchase Agreement, we issued the 12% Note and the 12% Note Warrants in a transaction intended to qualify for an exemption from registration under the Securities Act pursuant to Section 4(2) thereof and Regulation D promulgated thereunder.

The terms of the 12% Note Purchase Agreement and related agreements include the following:

Interest. The unpaid principal balance under the 12% Note bears interest (computed on the basis of a 360-day year of twelve 30-day months) payable semi-annually on June 30 and December 31, commencing December 31, 2006, in cash at the rate of 12% per annum and (b) at the rate of 15% per annum on any overdue payments of principal and interest.

Optional Prepayments. CanArgo may, at its option, upon at least not less than 60 days and not more than 120 days prior written notice, prepay at any time and from time to time after June 28, 2007, any part of the 12% Notes up to an aggregate of $5,000,000 in aggregate principal amount, in multiples of not less than $100,000, and at any time after June 28, 2008 the remaining outstanding principal amount at the following Redemption Prices (expressed as percentages of the principal amount so prepaid): 105% after June 28, 2007 and 103% after June 28, 2008, together with all accrued and unpaid interest.

Mandatory Prepayment. CanArgo will not take any action to consummate a Change of Control (or Change of Control contemplated by a Control Event) unless it shall offer to prepay all, but not less than all, of the 12% Note, on not less than 15 business days prior written notice, in the event of an occurrence of a Change of Control or Control Event. Mandatory prepayment of the 12% Note shall be in an amount equal to 101% of the outstanding principal amount of such 12% Note, together with interest on such 12% Note accrued to the date of prepayment. *Change in Control* is defined to mean (a) if CanArgo shall at any time cease to be a publicly held company or cease to have its capital stock traded on an exchange or (b) a transaction or series of related transactions pursuant to which (i) at least fifty-one percent (51%) of the outstanding shares of CanArgo s common stock or, on a fully diluted basis, shall subsequent to June 28, 2006 be owned by any person which is not related to or affiliated with CanArgo, (ii) if CanArgo merges into or with, consolidates with or effects any plan of share exchange or other combination with any person which is not related to or affiliated with CanArgo, or (iii) if CanArgo disposes of all or substantially all of its assets other than in the ordinary course of business; provided, the disposition of Tethys in an offering subject to certain conditions will not be deemed the disposition of all or substantially all of CanArgo s assets and *Control Event* is defined to mean (i) the execution by CanArgo or any material subsidiary of CanArgo which has guaranteed the indebtedness evidenced by the 12% Note (a CanArgo Group Member) of any agreement or letter of intent with respect to any proposed transaction or event or series of transactions or events which, individually or in the aggregate, may reasonably be expected to result in a Change in Control, or (ii) the execution of any written agreement which, when fully performed by the parties thereto, would result in a Change in Control.

Conversion. The 12% Note is convertible, in whole or in part, into shares of CanArgo common stock (CanArgo Conversion Stock) at a conversion price per share of $1.00 (the CanArgo Conversion Price), which is subject to adjustment: (a) if CanArgo issues any equity securities (other than pursuant to the granting of employee stock options pursuant to shareholder approved employee stock option plans or existing outstanding options, warrants and convertible securities, including without limitation the Company s Senior Secured Notes and Senior Subordinated Notes) at a price per share of less than $1.00 per share, as adjusted, determined net of all discounts, fees, costs and expenses incurred in connection with such issuance, in which case the CanArgo Conversion Price will be reset to such lower price. The CanArgo Conversion Price shall also be adjusted in connection with any stock split, stock dividend, reverse stock split, reclassification, recapitalization, combination, merger, consolidation or any similar transaction, in which case the CanArgo Conversion Price and number of shares of CanArgo Conversion Stock will be appropriately adjusted to reflect any such event, such that the holder of the 12% Note will receive upon conversion the identical number of shares of CanArgo common stock or other consideration or property to be received by the holder of the CanArgo common stock as if the holder had converted the 12% Note immediately prior to any such event as such amount would then be adjusted by reason of such stock split, stock dividend, reverse stock split, reclassification, recapitalization, combination, merger, consolidation or other similar transaction; provided, however, in no event shall the number of shares of CanArgo Common Stock issuable to the Purchasers upon conversion cause the Purchasers to collectively own in excess of 19.9% of the shares of CanArgo common stock outstanding as of June 28, 2006 absent shareholder approval in accordance with applicable stock exchange requirements. The 12% Note is subject to mandatory conversion under certain circumstances. No fractional shares of CanArgo common stock shall be issued upon any conversion; instead the CanArgo Conversion Price shall be appropriately adjusted so that holders shall receive the nearest whole number of shares upon any conversion.

In connection with the execution and delivery of the 12% Note Purchase Agreement, CanArgo entered into a Registration Rights Agreement with the Purchasers pursuant to which it agreed to register the CanArgo Conversion Stock and the Warrant Shares for resale under the Securities Act. The Registration Rights Agreement gives the holders of the 12% Notes and 12% Note Warrants both demand and piggyback registration rights. In addition the Registration Rights Agreement requires us to use our best efforts to have a registration statement declared effective by December 31, 2006 and to maintain that effectiveness for a period of two years in the event that we use a Form S-3 and at least 90 days in the event we use a Form S-1 to register the shares. There is no penalty associated with our failure to perform under the Registration Rights Agreement.

Security. Payment of all amounts due and payable under the 12% Note Purchase Agreement, the 12% Note and all related agreements (collectively, the Loan Documents) is secured by subordinated guarantees from each other CanArgo Group Member (the 12% Subordinated Subsidiary Guaranty). If CanArgo forms or acquires a Material Subsidiary (as defined in the 12% Note Purchase Agreement) it shall cause such Subsidiary to execute a 12% Subordinated Subsidiary Guaranty (other than for certain excepted companies and legal entities) and thereby become a CanArgo Group Member subject to the provisions of the 12% Note Purchase Agreement.

Subordination. Payments on the 12% Note and under the 12% Subordinated Subsidiary Guaranty is subordinated and junior in right of payment to the prior payment or conversion in full of CanArgo s Senior Indebtedness in the event of the bankruptcy, insolvency or other reorganization of CanArgo. Under the terms of the subordination, holders of the 12% Note agree for the benefit of the holders of the Senior Indebtedness to certain limitations on their right to accelerate or demand payment under the 12% Note or otherwise realize under the 12% Subordinated Subsidiary Guaranty in the event of a default under the Senior Indebtedness. *Senior Indebtedness* is defined to mean (i) all indebtedness under the Senior Secured Notes, the Senior Subordinated Notes, or any related agreements; (ii) certain permitted indebtedness now existing or hereafter arising, and (iii) all renewals, refinancings, extensions, modifications and replacements of the then outstanding principal amount owing under any of the foregoing.

Covenants. Under the terms of the 12% Note Purchase Agreement CanArgo is subject to certain affirmative and negative covenants, which can be waived by the beneficial holders of at least 50% of the outstanding principal amount of the 12% Notes (the Required Holders), including the following affirmative and negative covenants, respectively: (a) providing current information regarding CanArgo and rights of inspection; compliance with laws; maintenance of corporate existence, insurance and properties; payment of taxes; adding new material subsidiaries as additional guarantors under the 12% Subordinated Subsidiary Guaranty; payment of professional fees for the Purchaser (not in excess of $75,000), and (b) restrictions on: transactions with affiliates; mergers, consolidations and sales of all of CanArgo s assets; liens (except for certain permitted liens); the issuance of additional senior indebtedness; changes in CanArgo s line of business; certain types of payments; sale-and leasebacks; sales of assets other than in the ordinary course of business; future Indebtedness, as defined in the 12% Note Purchase Agreement (other than certain permitted indebtedness); cancelling, terminating, waiving or amending provisions of, or selling any interests in (other than under certain circumstances) any of the Basic Agreements (as defined in the 12% Note Purchase Agreement); and adopting any anti-take-over defences except as permitted by the 12% Note Purchase Agreement. CanArgo is not subject to any financial covenants, such as the maintenance of minimum net worth or coverage ratios, other than the restriction on its ability to incur additional Indebtedness.

Events of Default. An Event of Default shall exist if one or more of the following occurs and is continuing: (i) failure to pay when due any principal and, after 5 business days, any interest, payable under the 12% Note or any Loan Document; (ii) default in the performance of certain enumerated covenants; (iii) default in the performance or compliance with any other terms which remains unremedied for 30 days after the earlier of a Responsible Officer first obtaining actual and not constructive knowledge of the default or the receipt of notice; (iv) any representation or warranty made in writing on behalf of CanArgo or any other CanArgo Group Member proves to have been false or incorrect in any material respect; (v) customary events involving bankruptcy, insolvency or reorganization; (vi) the entry of a final judgment or judgments in excess of $2,500,000 (uncovered by insurance), which is not discharged or settled; (vii) violations of ERISA or the Internal Revenue Code of 1986, as amended, under funding of accrued benefit liabilities and other matters relating to employee benefit plans subject to ERISA or Foreign Pension Plans; (viii) any Loan Document ceases to be in full force and effect (except in accordance with its terms) or its validity is challenged by CanArgo or any affiliate; (ix) CanArgo or any other CanArgo Group Member modifies its Charter Document which results in a Default or Event of Default or will adversely affect the rights of 12% Note holders; or (x) a change occurs in the consolidated financial condition of CanArgo or in the physical, operational or financial status of the Properties (as defined in the Note Purchase Agreement), which change has a Material Adverse Effect (as defined in the Note Purchase Agreement).

Other than for certain Events of Default that will result in an automatic acceleration without notice, such as bankruptcy, if an Event of Default occurs and is continuing, the Required Holders may at any time at its or their option, by notice to CanArgo, declare all outstanding 12% Notes to be immediately due and payable and holders of the 12% Note may proceed to enforce their rights under the Loan Documents at law or in equity. CanArgo is responsible for the payment of all costs of collection, including all reasonable legal fees actually incurred in connection therewith.

12% Note Warrants. The 12% Note Warrants may be exercised at an exercise price of $1.00 per share, subject to adjustment (the Exercise Price) in whole or in part at any time during the period (the Exercise Period) commencing on the first Business Day six (6) months after the date of issuance and terminating at the close of business on June 28, 2008 or shall be exercised on such sooner date at the election of the Company (a Mandatory Exercise) and upon at least thirty (30) days prior written notice to the Registered Holder (the Mandatory Exercise Notice) in the event that: (i) the Manavi M12 well indicates, by way of an independent engineering report, sustainable production, if developed, in excess of 7,500 barrels of oil per day or (ii) all the warrants originally issued under that certain Note and Warrant Purchase Agreement dated as of March 3, 2006 by and among the Company and the holders of the Senior Subordinated Notes are exercised by the holders thereof and the average closing price for the CanArgo Common Stock on the American Stock Exchange or, if the CanArgo Common Stock is not then listed for CanArgo s trading on the American Stock Exchange then the Oslo Stock Exchange, is above $1.25 (or its equivalent in NOK, and in any case adjusted for any stock dividends, stock split, its reverse split, recapitalization or reorganization) for a period of five consecutive trading days (the Warrant Expiration Date); except that (a) in the case of a Mandatory Conversion (as defined in the 12% Note Purchase Agreement), any and all outstanding 12% Note Warrants issued under the 12% Note Purchase Agreement and held by Purchaser shall automatically and simultaneously become immediately exercisable on receipt of the Mandatory Conversion Notice, and (b) in the case of a Mandatory Exercise, any and all outstanding 12% Notes issued under the 12% Note Purchase Agreement and held by Purchaser shall automatically and simultaneously become immediately convertible on receipt of the Mandatory Exercise Notice. The Exercise Period may also be extended by the Company s Board of Directors. The Exercise Price is subject to adjustment in connection with any stock split, stock dividend, reverse stock split, reclassification, recapitalization, combination, merger, consolidation or any similar transaction, in which case the Exercise Price and number of Warrant Shares will be appropriately adjusted to reflect any such event, such that the holders of the 12% Note Warrants will receive upon exercise the identical number of shares of CanArgo common stock or other consideration or property to be received by the holders of the CanArgo common stock as if the holders had exercised the 12% Note Warrants immediately prior to any such event as such amount would then be adjusted by reason of such stock split, stock dividend, reverse stock split, reclassification, recapitalization, combination, merger, consolidation or other similar transaction. If CanArgo issues any equity securities (other than pursuant to the granting of employee stock options pursuant to shareholder approved employee stock option plans or existing outstanding options, warrants and convertible securities, including without limitation the conversion of the Senior Secured Notes or the Senior Subordinated Notes) at a price per share of less than $1.00 per share, as adjusted, determined net of all discounts, fees, costs and expenses incurred in connection with such issuance, the Exercise Price will be reset to such lower price; provided, however, in no event shall the number of Warrant Shares issuable upon exercise cause 12% Note Warrant holders to collectively own in excess of 19.9% of the shares of CanArgo common stock outstanding as of June 28, 2006 absent shareholder approval in accordance with applicable stock exchange requirements. The 12% Note Warrants may be converted at the election of the holders and with the concurrence of the Company into Warrant Shares on a net basis based upon the then spread between the Exercise Price and the market price of the Warrant Shares. No fractional shares of CanArgo common stock shall be issued upon any exercise; instead the Exercise Price shall be appropriately adjusted so that holders shall receive the nearest whole number of shares upon any conversion.

Miscellaneous. The execution of the 12% Note Purchase Agreement was conditional upon the consent, which was obtained, from 51% of the holders of the Senior Secured Notes and from 50% of the holders of the Senior Subordinated Notes each pursuant to Waiver and Consent Agreements each dated as of June 28, 2006. Under the terms of their Waiver and Consent Agreement, the holders of 51% in aggregate principal amount of the Senior Secured Notes further agreed to issue to the Purchaser an option to purchase their Senior Secured Notes at par in the event of Default and acceleration of the Senior Secured Notes provided that the Purchaser concurrently offers to purchase the remaining outstanding Senior Secured Notes on identical terms and conditions. The 12% Note Purchase Agreement, the 12% Note, the 12% Subordinated Subsidiary Guaranty and the Registration Rights Agreement are all governed by New York Law and the 12% Note Warrants are governed by the laws of the State of Delaware; the CanArgo Group Members party thereto subject themselves to the jurisdiction of New York Courts and waive the right to jury trial.

The Company evaluated the embedded conversion feature in this debt and determined it did not meet the criteria for bifurcation under SFAS No 133 Accounting for Derivative Instruments and Hedging Activities during the quarter.

Pursuant to EITF 98-5 Accounting for Convertible Securities with Beneficial Conversion Features or Contingently Adjustable Conversion Ratios and EITF 00-27 Application of Issue No. 98-5 to Certain Convertible Instruments , the Company has recorded a discount to the 12% Note in the amount of approximately $2,700,000 based on the relative fair value of the beneficial conversion feature and warrants of $50,000 be and $2,650,000, respectively.

We used the following assumptions to determine the fair value of the 12% Note and 12% Note Warrants:

	Additional Loan
Stock price on date of grant	$ 0.74
Risk free rate of interest	5.30%
Expected life of warrant days	731
Dividend rate	
Historical volatility	64.3%

The discount is being amortized to interest expense over the life of the 12% Note using an effective interest rate of 10.1%. As of December 31, 2006 we had amortized $303,279 of debt discount as interest expense. The total effective interest rate for the 12% Note is 22.1%.

Senior secured notes in Tethys: On September 7, we announced that Tethys had completed a $5 million interim loan financing (the Tethys Bridge) to fund Tethys development activities in Kazakhstan ahead of Tethys planned spin-out and admission to the AIM market in London later that year. The funds are to be used by Tethys primarily for the purchase of pipeline, compressors and related equipment and services for the Kyzyloi field development. The financing took the form of the issue of $5 million senior secured notes in Tethys redeemable on August 31, 2008 (the Tethys Notes) pursuant to a note and warrant or royalty purchase agreement dated September 5, 2006 (the Tethys NPA). Pursuant to the Tethys NPA, Tethys has the ability to pre-pay the Tethys Notes and the Tethys Notes fall to be automatically pre-paid in full following a change of control of Tethys which includes the admission of Tethys to AIM. Tethys has granted security over its bank account with HSBC Bank plc and its shareholding in its wholly owned subsidiary, Tethys Kazakhstan Limited,

as a condition of the Tethys NPA with such security to be released on repayment of the funds. The Tethys Notes bear interest at the rate of 10% per annum for the period from the date of issue until December 31, 2006 and 15% per annum from January 1 2007 until they are repaid in full. The Tethys NPA contains certain affirmative and negative covenants on Tethys which apply provided at least $500,000 in aggregate of the Tethys Notes is outstanding. The affirmative and negative covenants require Tethys among other things to maintain its corporate existence, to maintain insurance coverage on such terms and in such amounts as is customary in the case of entities in the same or similar businesses and which are similarly situated, to keep current with respect to payment of all due and payable taxes, to not permit Tethys to engage in transactions with affiliates unless they are in the ordinary course of business and on arm s length terms, to not enter into mergers or consolidations while an default or event of default is continuing or to allow liens on any pledged or secured assets under the NPA except specified permitted liens. In addition, while the covenants still apply Tethys must seek the permission of the noteholders to incur additional external third-part indebtedness in excess of $2,500,000 except permitted indebtedness as specified in the Tethys NPA.

Pursuant to the provisions of Emerging Issue Task Force 86-15: Increasing-Rate Debt , the Company recognizes interest expense using the effective interest rate method, which results in the use of a constant interest rate for the life of the Tethys Notes. The effective interest rate is approximately 14.2% per annum. The difference between the interest computed using the actual interest rate in effect (10% per annum to December 31, 2006 and 15% from January 1, 2007) and the effective interest rate (14.2% per annum) totalled $66,715 as of December 31, 2006 of which $35,000 has been included in accrued liabilities and $31,715 has been accrued as a non-current liability.

Under the terms of the Tethys NPA, the holders of the Tethys Notes are entitled to receive additional consideration for the advance of the loan in the form of either (1) at closing of the fundraising, warrants to subscribe for ordinary shares in the capital of Tethys (the Tethys Warrants) or (2) 90 days following first commercial sale of hydrocarbons, in which case Tethys may chose between granting the noteholder Tethys Warrants or entering into a royalty agreement with the noteholder. The Tethys Warrants shall be issued pursuant to the terms of an instrument by way of deed poll entered into by Tethys on September 5, 2006. The Tethys Warrants are exercisable in whole or in part at any time up to the expiry of 60 months from the date of the Tethys NPA. As of December 31, 2006, the number of ordinary shares in the capital of Tethys into which the Tethys Warrants are exercisable and the exercise price of the Tethys Warrants are based on an assumed valuation of Tethys, however, in the event of an AIM listing prior to July 31, 2007 the number of shares and exercise price change to become based on the listing price and valuation of the AIM listing. One of the noteholders elected to receive their Tethys Warrants at the closing of the fundraising. The other noteholder shall receive their additional consideration 90 days from first commercial sale of hydrocarbons by Tethys.

The requisite holders of the Senior Secured Notes, Senior Subordinated Notes and 12% Notes provided their consent to the Tethys Bridge as required under their respective Note Purchase Agreements.

The Tethys NPA, Tethys Notes, Tethys Warrants and the Warrant Instrument are governed by English law.

The Company evaluated the additional consideration for advancing its loan to Tethys 90 days after first commercial sale of hydrocarbons by Tethys for potential derivative treatment and determined it did not meet the criteria for bifurcation under SFAS No 133 Accounting for Derivative Instruments and Hedging Activities during the quarter.

Pursuant to EITF 98-5 Accounting for Convertible Securities with Beneficial Conversion Features or Contingently Adjustable Conversion Ratios and EITF 00-27 Application of Issue No. 98-5 to Certain Convertible Instruments , the Company has recorded a discount to the Tethys Notes in the amount of approximately $2,220,000 based on the relative fair value of the Tethys Warrants.

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We used the following assumptions to determine the fair value of the Tethys Warrants:

	Additional Loan
Stock price on date of grant	$ 0.74
Risk free rate of interest	4.73%
Expected life of warrant months	60
Dividend rate	
Historical volatility	110.5%

The discount is being amortized to interest expense over the life of the Tethys Warrants using an effective interest rate of 18.7%. As of December 31, 2006 we had amortized $303,673 of debt discount as interest expense. The total effective interest rate for the Tethys Note is 32.9%.

NOTE 12 DEFERRED REVENUE

Other liabilities consisted of the following at December 31:

	2006	2005
Prepaid sales	$ 484,515	$
	$ 484,515	$

As of December 31, 2006 prepaid sales relate to a deposit received from a customer for a sale of oil to be completed in 2007.

NOTE 13 ACCRUED LIABILITIES

Accrued liabilities consisted of the following at December 31:

	2006	2005
Drilling contractors	$ 5,144,255	$ 4,984,261
Professional fees	1,035,480	1,005,000
Non-cash loan interest	925,800	
Other	281,695	367,362
	$ 7,387,230	$ 6,356,623

Included in the amounts due to drilling contractors at December 31, 2006 are amounts invoiced by Weatherford of $4,931,332. We have formally notified Weatherford that we dispute the validity of these billings to the Company for work Weatherford performed in the first and second quarter of 2005. We have recorded all amounts billed by Weatherford as of December 31, 2006 pending the outcome of the dispute resolution which may require referral to the London Court of International Arbitration for resolution in accordance with the provisions of the contract.

NOTE 14 MINORITY INTEREST

Tethys Petroleum Investments Limited

In September 2003, together with Atlantic Caspian Resources plc (ACR), we formed a limited partnership, Tethys Petroleum Investments Limited (TPI) and its wholly owned subsidiary Tethys Kazakhstan Ltd (TKI). As part of this investment, ACR contributed its 70% ownership interest in BN Munai LLP (BN Munai) into TKI in exchange for 10% ownership of TPI and we committed to funding the day to day operations and provide management services until third party financing could be arranged in exchange for 90% ownership of TPI. BN Munai s interest centers on the Akkulka exploration area and the Kyzyloi Gas Field, located in western Kazakhstan, just to the west of the Aral Sea. In the four years prior to our ownership interest, ACR drilled two deep exploration wells inthe Akkulka area, which they plugged and abandoned after demonstrating the presence of hydrocarbons, due to funding limitations on their part. On the same day that we consummated the transaction to create TPI, we entered into an agreement to sell half of our ownership interest in TPI to Provincial Securities Limited, an investment company to which Mr. Russell Hammond, one of our non- executive directors, is an Investment Advisor, in consideration for future services of providing advice to us concerning funding the development of TPI as we intended to fund the majority of the development of the Kyzyloi Gas Field through third party financing.

The following day we entered into a Technical Services Agreement and a Loan Agreement with TPI in which we agreed to provide our managerial expertise and to provide cash advances to fund and manage the day to day operations of TPI and to provide funding to secure additional site licenses within the vicinity of the Kyzyloi Gas Field. The advances under the agreement, both cash and the value of services we perform on behalf of TPI, bear interest at the rate of 10% per annum and are repayable immediately upon the receipt by TPI of third party financing.

On June 9, 2005, through our acquisition of the remaining 55% of Tethys Petroleum Investments Limited (See Notes 3 and 24) we acquired a 70% ownership interest in BN Munai (BN Munai). BN Munai has only suffered losses from inception and currently the Company is the only partner funding the current operating losses, therefore, no minority interest is recorded at December 31, 2005 for the 30% ownership not under our control. The Company does not expect the minority partners in BN Munai to contribute funds to the partnership.

The Company has recorded 100% of its losses in BN Munai for 2006 and 2005, as it is the only funding partner.

Under a loan agreement with BN Munai, TKL will take 100% of the net cash flow of the Kyzyloi development until the loan is repaid. The principal loan value of $9,389,162 plus interest of $805,451 was accrued as of the loan agreement date and was originally assigned to TKL from ACR as part of its exchange of its 70% ownership interest in BN Munai for 10% ownership of TPI. As at December 31, 2006 the principal amount of the loan outstanding was $27,897,380 plus accrued interest of $1,590,287. Interest is recorded in line with the loan agreement using a 3 month LIBOR rate as at the first business day of each quarter.

CanArgo Norio Limited

In September 2003, CanArgo Norio Limited (CNL) signed a Farm-In agreement (the Agreement) relating to the Norio PSA with a wholly owned subsidiary of Georgian Oil, the Georgian State Oil Company (Georgian Oil). Georgian Oil is already a party to the Norio PSA as the commercial representative of the State. The Agreement obligates Georgian Oil to pay up to $2,000,000 to complete the MK-72 well on the Norio prospect in return for a 15% interest in the contractor share of the Norio PSA. Georgian Oil would also have an option (the Option) exercisable for a limited period after completion of the well, to increase its interest to 50% of the contractor share of the Norio PSA on payment to CNL of $6,500,000.

Coincident with the Georgian Oil farm-in, we concluded a transaction to purchase some of the minority interests in CNL by a share swap for shares in CanArgo. Through this exchange we acquired an additional 10.8% interest in CNL increasing our interest to 75%. This maintains our effective interest in the Norio PSA after Georgian Oil has completed the first stage of the farm-in at approximately 63.7%. The purchase was achieved by issuing 6,000,000 restricted CanArgo shares to the minority interest holders in CNL. Of the interests in CNL, 4% were owned by Provincial Securities Limited, a company to which Mr. Russell Hammond, a non-executive director of CanArgo, is a financial advisor. Provincial Securities Limited received 2,273,523 shares of common stock in return for their interest. In the event that Georgian Oil exercises the Option and pays the required $6,500,000 to CNL we would be obligated to issue a further 3,000,000 restricted shares to the minority interest holders.

On September 30, 2004 we announced that we had increased our interest in CNL, by buying out the remaining minority shareholder in that company, NPET Oil Limited. CNL will now become a wholly owned subsidiary of CanArgo. Following completion of the Georgian Oil farm-in to the Norio PSA, CNL will hold an 85% interest in the Norio PSA. CNL also holds 100% of the contractor s interest in the Block XI^{G} and XI^{H} Production Sharing Contract (Tbilisi PSC). This transaction has therefore increased our interest in the Norio PSA by 21.25%, and by 25% in the Tbilisi PSC. We have issued 6,000,000 restricted shares of our common stock valued at $4,320,000 to NPET Oil Limited in connection with this transaction. Upon recording this transaction, minority interest of $1,351,022 was reduced to $0 and oil and gas properties increased by $2,968,978. At the same time, our commitment under the Norio PSA and the original shareholders agreement for a bonus payment of $800,000 to be paid by us to the other shareholders should commercial production be obtained from the Middle Eocene or older strata and a second bonus payment of $800,000 should production exceed 250 tonnes (approximately 1,900 barrels) of oil per day over any 90 day period has terminated.

CanArgo Standard Oil Products Limited

In September 2002, we approved a plan to sell our interest in CanArgo Standard Oil Products Limited (CSOP), a petroleum product retail business in Georgia, to finance our Georgian and Ukrainian development projects. In October 2002, we reached agreement with Westrade Alliance LLC, an unaffiliated company, to sell our wholly owned subsidiary, CanArgo Petroleum Products Limited (CPPL), which held our 50% interest in CSOP for $4,000,000 in an arms-length transaction, with legal ownership being transferred upon receipt of final payment dueoriginally in August 2003 and subsequently extended. The final payment of the consideration was received by us in December 2004 at which time we transferred our ownership in CPPL to Westrade Alliance LLC. The results of CSOP s operations have been presented for financial statement purposes as discontinued operations (See Note 20 Discontinued Operations).

Georgian American Oil Refinery

In November 2000, we completed the acquisition of a 51% interest in the Georgian American Oil Refinery (GAOR), a company which owns a small refinery located at Sartichala, Georgia. From that date, GAOR became a subsidiary of CanArgo and its results have been included in our consolidated financial statements. However, due to operational difficulties and changes to the fiscal system in Georgia, GAOR ceased to operate during 2001.

As a result of the uncertainty as to the ultimate recoverability of the carrying value of the refinery, we recorded in 2001 a write-down of the refinery s property, plant and equipment of approximately $3,500,000. During 2003, a debit balance of $1,274,895 in minority interest was written-off due to a change in the intentions of our minority interest owner and a plan to dispose of the asset. In 2004, we came to an agreement to sell our interest in the refinery. Our interest in the refinery was sold in February 2004.

NOTE 15 COMMITMENTS AND CONTINGENCIES

We have contingent obligations and may incur additional obligations, absolute and contingent, with respect to the acquisition and development of oil and gas properties and ventures in which we have interests that require or may require us to expend funds and to issue shares of our Common Stock.

At December 31, 2006, we have commitments of $4,063,000 in respect of the construction of the pipeline tie-in for the Kyzyloi field development in Kazakhstan.

At December 31, 2006, we had the contingent obligation to issue an aggregate of up to 187,500 shares of our Common Stock to Fielden Management Services PTY, Ltd (a third party management services company), subject to the satisfaction of conditions related to the achievement of specified performance standards by the Stynawske Field project, an oil field in Ukraine in which we had a previous interest. As far as management is aware, the project is not progressing at the desired pace of development and consequently, in management s opinion the chance of having to issue these shares is remote.

Under the Tbilisi PSC we have a commitment to evaluate existing seismic and geological data which we have completed, and acquire additional seismic data within three years of the effective date of the contract which is September 29, 2003. The State Agency for Oil & Gas Regulation in Georgia verbally consented to an extension to the period within which the data should be acquired to the end of 2007, but due to an internal reorganisation of the State Agency, we are only now working with the State Agency to amend the Tbilisi PSC accordingly. The total commitment over the remaining period is $350,000.

In 2002, the Participation Agreement for the three well exploration program on the Ninotsminda/Manavi area with AES Gardabani (a subsidiary of AES Corporation) (AES) was terminated without AES earning any rights to any of the Ninotsminda/Manavi area reservoirs. We therefore have no present obligations in respect of AES. However, under a separate Letter of Agreement, if gas from the Sub Middle Eocene is discovered and produced from the exploration area covered by the Participation Agreement, AES will be entitled to recover at the rate of 15% of future gas sales from the Sub Middle Eocene, net of operating costs, approximately $7,500,000, representing their prior funding under the Participation Agreement. AES have now withdrawn from Georgia, but hydrocarbons have been discovered in the Manavi area reservoir and in the event of a successful gas development from the Sub Middle Eocene, it is reasonably possible that AES may exercise their rights under the Letter of Agreement.

On February 4, 2005, NOC and Primrose Financial Group (PFG) agreed to the terminate the Sales Agreement and enter into a new agreement (New Agreement) whereby PFG would receive an immediate repayment of its Security Deposit and obtain an extended term over which it can purchase crude oil produced from the Ninotsminda Field while NOC receives better commercial terms for the sale of its production. The New Agreement has a minimum term of 45 months.

During 2006, PFG was not able to comply with the terms of the New Agreement and the New Agreement was subsequently terminated with neither party having any continuing obligations. Since the termination of the New Agreement, NOC has sold its share of production to third parties under short term sales agreements.

On July 27, 2005, GBOC Ninotsminda, an indirect subsidiary of the Company, received a claim raised by certain of the Ninotsminda villagers (listed on pages 1 to 76 of the claim) in the Tbilisi Regional Court in respect of damage caused by the blowout of the N100 well on the Nintosminda Field in Georgia on September 11, 2004. An additional claim was received in December 2005 and amended in March 2006, thus bringing the relief sought pursuant to both claim to the sum of approximately 314,000,000 GEL (approximately $184,000,000 at the exchange rate of GEL to US dollars in effect on December 31, 2006). We believe that we have meritorious defenses to this claim and intend to defend it vigorously and as a result of discussions with our legal advisors in Georgia, we would consider the chances of the claim being successful to be remote.

On September 12, 2005, WEUS Holding Inc (WEUS) a subsidiary of Weatherford International Ltd lodged a formal Request for Arbitration with the London Court of International Arbitration against CanArgo Energy Corporation in respect of unpaid invoices for work performed under the Master Service Contract dated June 1, 2004 between the Company and WEUS for the supply of under-balanced coil tubing drilling equipment and services during the first and second quarter of 2005. Pursuant to the Request for Arbitration, WEUS demand for relief is $4,931,332.55. Although the Company has recorded all amounts billed by Weatherford as of December 31, 2005 (see Note 13) the Company is contesting the claim and intends to file a counterclaim. We believe that we have meritorious defenses to this claim and intend to defend it vigorously. At this point in the proceedings it is not possible to predict the outcome of the arbitration. However, in the event that Weatherford is successful, the extent of the loss to the Company would be limited to payment of Weatherford s professional fess in regards to this matter.

The Company has been named in with a group of defendants by former interest holders of the Lelyaki oil field in Ukraine. The plaintiffs are seeking damages of approx 600,000 CDN (approx $517,000 at December 31, 2006 exchange rates). The former owners of UK-Ran Oil Company disposed of their investment in the field prior to selling the Company to CanArgo. CanArgo believes the claim against it to be meritless. The Company is unable at this time to determine a potential outcome but in general would consider the chances of the claim being successful to be remote.

Under the Ninotsminda PSC, Ninotsminda Oil Company Ltd is required to relinquish at least half of the area then covered by the production sharing contract, but not in portions being actively developed, at five year intervals commencing December 1999. In 1998, these terms were amended with the initial relinquishment being due in 2008 and a reduction in the area to be relinquished at each interval from 50% to 25% whereby the Contractor selects the relinquishment portions.

CanArgo Norio Limited currently owns a 100% interest in the Norio (Block XI(C)) and North Kumisi Production Sharing Agreement (Norio PSA), although this interest has a 25 year term it may be reduced to 85% should the state oil company, Georgian Oil, exercise an option available to it under the PSA for a limited period following the submission of a field development plan. Although we are not able to speak for Georgian Oil, in management s opinion it is likely that Georgian Oil would exercise the option available to it in the event of a commercial oil or gas discovery. As a contractor party, Georgian Oil would be liable for all costs and expenses in relation to any interest it may acquire in the PSA. This PSA covers an area of approximately 265,122 acres (1,061 Km^2) following a 25% relinquishment in April 2006 and will be subject to a further 50% relinquishment of the remaining contract area less any development area in April 2011.

Lease Commitments We lease office space under non-cancelable operating lease agreements. Rental expense for the years ended December 31, 2006, 2005 and 2004 was $558,043, $456,908, and $379,102 respectively. Future minimum rental payments over the next five years for our lease obligations as of December 31, 2006, are as follows:

2007	$ 844,588
2008	370,088
2009	370,088
2010	215,055
2011	60,022
Thereafter	165,061*
	$ 2,024,902

* This represents payments for 2 years and 9 months after 2011.

Total sub-rental income due to the Company over the next 3 years and 6 months under sub-leases is $560,349.

No parent company guarantees have been provided by CanArgo with respect to our contingent obligations and commitments.

NOTE 16 TEMPORARY EQUITY

Our 2004 Plan allows for up to 17,500,000 shares of the Company s common stock to be issued to officers, directors, employees, consultants and advisors pursuant to the grant of stock based awards, including qualified and non-qualified stock, options, restricted stock, stock appreciation rights and other stock based performance awards. Stock options may be exercised, in whole or in part, by giving written notice of exercise to the Corporation specifying the number of shares to be purchased. However, in the event of Change of Control (as defined in the 2004 Plan) an optionee (other than an optionee who initiated a Change of Control in a capacity other than as an officer or director of the Corporation) may elect to surrender all or part of the stock option to the Corporation and to receive in cash an amount equal to the amount by which the fair market value per share of the Stock on the date of exercise shall exceed the purchase price per share under the stock option multiplied by the number of shares of the Stock granted under the stock option as to which the right granted by this proviso shall have been exercised.

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The Company accounts for options issued with redemption features in accordance with SEC Accounting Series Release 268 Presentation in Financial Statements of Redeemable Preferred Stocks , and EITF D-98: Classification and measurement of Redeemable securities. the Company has calculated and classified the intrinsic value of $2,119,530 as at December 31, 2005 to Temporary Equity, the vested portion of issued share options from our 1995 Long-Term Incentive Plan in accordance with the related guidance. The Company believes that the likelihood of a Change in Control is remote at this point in time and therefore has fixed its Temporary Equity as at the December 31, 2005 level.

NOTE 17 STOCKHOLDERS EQUITY

On July 8, 1998, at a Special Meeting of Stockholders, the stockholders of CanArgo approved the acquisition of all of the common stock of CanArgo Oil and Gas (CAOG) for Common Stock of the Company pursuant to the terms of an Amended and Restated Combination Agreement between those two companies (the Combination Agreement). Upon completion of the acquisition on July 15, 1998, CAOG became a subsidiary of CanArgo, and each previously outstanding share of CAOG common stock was converted into the right to receive 0.8 shares (the Exchangeable Shares) of CAOG which are exchangeable generally at the option of the holders for shares of CanArgo s Common Stock on a share-for-share basis.

On January 24, 2002 we announced that we had established May 24, 2002 as the redemption date for all of the Exchangeable Shares of CAOG since the number of outstanding Exchangeable Shares had fallen below the minimum 853,071 share threshold. Each Exchangeable Share was purchased by CanArgo for shares of CanArgo Common Stock on a share-for-share basis resulting in the issuance of an aggregate of 148,826 shares of Common Stock. No cash consideration was issued by CanArgo and the purchase did not increase the total number of shares of Common Stock of CanArgo deemed issued and issuable.

In February 2004, we announced that we had signed a Standby Equity Distribution Agreement that allowed us, at our option, to issue shares to US-based investment fund Cornell Capital Partners LP up to a maximum value of $20,000,000 over a period of up to two years from the date on which the Registration Statement on Form S-3 registering for resale the shares under the Securities Act of 1933, as amended (Securities Act) is declared effective. The Registration Statement was declared effective by the SEC on February 3, 2005

In October 2006, we issued an aggregate of 12,263,368 shares of common stock in connection with a private placement in Norway intended to qualify for the exemption from registration afforded by Section 4(2) of The Securities Act of 1933, as amended (Securities Act) and Regulation S promulgated under the Securities Act, for aggregate gross proceeds of NOK (Norwegian Kroner) 111,596,239 ($16,687,039 equivalent based upon a conversion rate of NOK 6.6876 per dollar) before placing fees and expenses estimated at NOK 6,695,774 ($1,001,222 equivalent). We agreed to register the Shares for resale under the Securities Act. As a result of the delays incurred in registering the Reg. S Shares we have paid subscribers a cash liquidity penalty of 5% of the subscription price of their Shares in the aggregate amount of NOK 5,579,812 ($834,352 equivalent). The Registration statement was declared effective by the SEC on January 19, 2007.

The total number of shares of common stock authorized was 375,000,000 as of December 31, 2006 and 300,000,000 as of December 31, 2005 and 2004.

As of December 31, 2006 and 2005, we had 5,000,000 shares of $0.10 par value preferred stock authorized, of which none were outstanding. The Board of Directors may at any time issue additional shares of preferred stock and may designate the rights and privileges of a series of preferred stock without any prior approval by the stockholders.

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During the years ended December 31, 2006, 2005 and 2004, the following transactions regarding CanArgo s Common Stock were consummated pursuant to authorization by CanArgo s Board of Directors or duly constituted committees thereof.

Year Ended December 31, 2006

In February 2006, 1,521,739 shares of our common stock were issued converting the Ozturk Long Term Loan with Detachable Warrants.

In September 2006, 774,000 shares of our common stock were issued at an average of $0.76 per share as a result of employees exercising stock options.

In October 2006, 12,263,368 shares of our common stock were issued at $1.36 per share in relation to a private placement in Norway.

Year Ended December 31, 2005

We issued to Cornell Capital Partners, L.P. pursuant to the Standby Equity Distribution Agreement, the following shares at the dates and prices indicated:

In February 2005, 380,836 shares of our common stock were issued at $1.31 per share.

In February 2005, 335,653 shares of our common stock were issued at $1.47 per share.

In March 2005, 344,758 shares of our common stock were issued at $1.54 per share.

In March 2005, 370,599 shares of our common stock were issued at $1.62 per share.

In March 2005, 381,170 shares of our common stock were issued at $1.57 per share.

In March 2005, 495,745 shares of our common stock were issued at $1.21 per share.

In April 2005, 552,639 shares of our common stock were issued at $1.09 per share.

In April 2005, 473,634 shares of our common stock were issued at $1.27 per share.

In May 2005, 837,054 shares of our common stock were issued at $0.72 per share.

In May 2005, 813,670 shares of our common stock were issued at $0.74 per share.

In May 2005, 872,854 shares of our common stock were issued at $0.69 per share.

In May 2005, 847,458 shares of our common stock were issued at $0.71 per share.

In June 2005, 801,068 shares of our common stock were issued at $0.75 per share.

In June 2005, 812,348 shares of our common stock were issued at $0.74 per share.

In June 2005, 639,591 shares of our common stock were issued at $0.94 per share.

In June 2005, 596,421 shares of our common stock were issued at $1.00 per share.

In July 2005, 613,246 shares of our common stock were issued at $0.98 per share.

In July 2005, 630,120 shares of our common stock were issued at $0.95 per share.

In July 2005, 669,568 shares of our common stock were issued at $0.90 per share.

In July 2005, 761,325 shares of our common stock were issued at $0.79 per share.

In August 2005, 783,188 shares of our common stock were issued at $0.77 per share.

Other Stock issuances were as follows:

In March 2005, 1,067,833 shares of our common stock were issued at an average of $0.34 per share as a result of employees exercising stock options.

In March 2005, 1,570,000 shares of our common stock were issued at an average of $0.11 per share as a result of employees exercising stock options.

In May 2005, 80,000 shares of CanArgo common stock were issueable to CEOcast Inc in relation to a consultancy agreement between CanArgo and CEOcast.

In June 2005, 5,500,000 shares of our common stock were issued at $0.76 per share to Provincial, of which Russell Hammond (one of our non-executive directors) is Investment Advisor and 5,500,000 shares of our common stock were issued at $0.76 per share to Vando, in connection with the Tethys Acquisition.

In August 2005, 360,000 shares of our common stock were issued at an average of $1.44 per share as a result of stock options being exercised.

In September 2005, 284,000 shares of our common stock were issued at an average of $1.34 per share as a result of stock options being exercised

Year Ended December 31, 2004

In February 2004, 163,218 shares of our common stock were issued at $0.56 per share to Cornell Capital Partners, L.P. as part payment of the commitment fee payable pursuant to the Standby Equity Distribution Agreement between Cornell and the Company (Equity Line of Credit).

In February 2004, 30,799 shares of our common stock were issued at $0.33 per share to Newbridge Securities Corporation pursuant to the Placement Agent Agreement among CanArgo Energy Corporation, Newbridge Securities Corporation and Cornell Capital Partners in terms of which Newbridge advised the Company and acted as our exclusive placement agent in respect of the Equity Line of Credit.

In March 2004, 3,815,084 shares of CanArgo common stock were issued at an average of $0.13 per share as a result of employees exercising stock options.

In April, 2004 we issued 4,000,000 shares of CanArgo common stock at $0.94 per share to Europa Oil Services Limited pursuant to a consultancy agreement to acquire an interest in the Samgori PSC.

In July, 2004 we issued 80,000 shares of CanArgo common stock at 0.70 per share to CEOcast Inc in relation to a consultancy agreement between CanArgo and CEOcast Inc dated May 17, 2004.

In July 2004, we issued 425,000 shares of our common stock at $0.50 per share to Cornell Capital Partners, L.P. as part payment of the commitment fee payable pursuant to the Standby Equity Distribution Agreement between Cornell and the Company (Equity Line of Credit).

In September 2004, we completed a global public offering (Global Offering) of 75 million shares of our common stock at an offering price of $0.50 per share. We raised gross proceeds of $37,500,000 and paid total commissions and expenses related to the Global Offering of $4,543,845 which resulted in net proceeds to the Company of $32,956,155.

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In September, 2004 we issued 6,000,000 restricted shares of our common stock at $0.60 per share to NPET Oil Limited to increase our interest in CanArgo Norio Limited, by buying out the remaining minority shareholder in that company, NPET Oil Limited.

In November 2004, 80,000 shares of CanArgo common stock were issueable to CEOcast Inc in relation to a consultancy agreement between CanArgo and CEOcast.

NOTE 18 NET LOSS PER COMMON SHARE

Earnings (loss) per share is calculated in accordance with SFAS No. 128, Earnings Per Share. Basic and diluted earnings per share are provided for continuing operations, discontinued operations, cumulative effect of change of accounting principle and net income (loss). Basic earnings (loss) per share is computed based upon the weighted average number of shares of common stock outstanding for the period and excludes any potential dilution. Diluted earnings per share reflects potential dilution from the exercise of securities (warrants, options and convertible debt) into common stock. Outstanding options and warrants to purchase common stock are not included in the computation of diluted loss per share because the effect of these instruments would be anti-dilutive for the loss periods presented.

Basic and diluted net loss per common share for the years ended December 31, 2006, 2005 and 2004 were based on the weighted average number of common shares outstanding during those periods. Shares issuable upon the conversion of convertible notes, options and warrants to purchase CanArgo s Common Stock were outstanding during the years ended December 31, 2006, 2005 and 2004 but were not included in the computation of diluted net loss per common share because the effect of such inclusion would have been anti-dilutive (i.e. reduce the loss per share). The total number of such shares excluded from diluted net loss per common share were 97,365,214, 41,644,516 and 14,834,080 for each of the years ended December 31, 2006, 2005 and 2004 respectively (See Notes 14 and 24).

NOTE 19 INCOME TAXES

CanArgo and its U.S. domestic subsidiaries file a U.S. consolidated income tax return. No benefit for U.S. income taxes has been recorded in these consolidated financial statements because of CanArgo s inability to recognize deferred tax assets under provisions of SFAS 109. Due to the implementation of the quasi-reorganization as of October 31, 1988, future reductions of the valuation allowance relating to those deferred tax assets existing at the date of the quasi-reorganization, if any, will be allocated to capital in excess of par value.

A reconciliation of the differences between income taxes computed at the U.S. federal statutory rate of 34% and CanArgo s reported provision for income taxes is as follows:

	Year Ended December 31,		
	2006	2005	2004
Income tax benefit at statutory rate	$ (20,583,889)	$ (4,194,007)	$ (1,617,548)
Benefit of losses not recognized	20,583,889	4,194,007	1,617,548
Provision for income taxes	$	$	$
Effective tax rate	0%	0%	0%

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The components of deferred tax assets consisted of the following as of December 31:

	2006	2005
Net operating loss carryforwards	$ 11,059,000	$ 7,775,000
Foreign net operating loss carryforwards	2,794,000	2,961,000
Net timing differences on impairments and accelerated capital allowances	9,553,000	9,383,000
	23,406,000	20,119,000
Valuation allowance	(23,406,000)	(20,119,000)
Net deferred tax asset recognized in balance sheet	$	$

On August 1, 1991, August 17, 1994, July 15, 1998 and June 28, 2000, CanArgo experienced changes in ownership as defined in Section 382 of the Internal Revenue Code (IRC). The effect of these changes in ownership is to limit the utilization of certain existing net operating loss carryforwards for income tax purposes to approximately $2,920,000 per year on a cumulative basis. As of December 31, 2006, total unexpired U.S. net operating loss carryforwards were approximately $47,903,000, approximately $20,312,000 of this amount was incurred prior to the ownership change in 2000 and as a result of IRC Section 382 limitations approximately $15,375,000 of those carryforwards will expire unused.

The U.S. net operating loss carryforwards expire from 2007 to 2026. CanArgo also has approximately $8,217,000 of foreign net operating loss carryforwards. A significant portion of the foreign net operating loss carryforwards may be subject to limitations similar to IRC Section 382.

CanArgo s available net operating loss carryforwards may be used to offset future taxable income, if any, prior to their expiration. CanArgo may experience further limitations on the utilization of net operating loss carryforwards and other tax benefits as a result of additional changes in ownership.

NOTE 20 DISCONTINUED OPERATIONS

Samgori PSC

On February 17, 2006 we issued a press release announcing that our subsidiary, CanArgo Samgori Limited (CSL), was not proceeding with further investment in Samgori (Block XI ^{B}) Production Sharing Contract (Samgori PSC) in Georgia and associated farm-in which became effective in April 2004, and accordingly we terminated our 50% interest in the Samgori PSC with effect from February 16, 2006. The decision by CSL not to proceed with further investment under the current farm-in arrangements was due to the inability of CSL s partner in the project, Georgian Oil Samgori Limited (GOSL), to provide its share of funding to further the development of the Field. We consider that there would have been insufficient time to meet the commitments under the Agreement with National Petroleum Limited (NPL) the previous licence holders and we were not prepared to fund the project, which is not without risk, on a 100% basis without different commercial terms and an extension to the commitment period. It was not possible to negotiate a satisfactory position on either matter. CSL has been informed that NPL has now exercised its right to take back 100% of the Contractor Share in the Samgori PSC from GOSL and, accordingly, effective February 16, 2006 we have withdrawn from the Samgori PSC.

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The results of discontinued operations in respect of CSL consisted of the following for the years ended:

	December 31, 2006	December 31, 2005	December 31, 2004
Operating Revenues	**$ 1,002,842**	$ 2,303,463	$ 1,741,626
Income Before Income Taxes and Minority Interest	**672,803**	603,170	961,797
Income Taxes			
Minority Interest in Income			
Net Income from Discontinued Operation	**$ 672,803**	$ 603,170	$ 961,797

Gross consolidated assets and liabilities in respect of CSL that are included in assets to be disposed consisted of the following at December 31:

	December 31, 2006	December 31, 2005
Assets to be disposed:		
Accounts receivable (net)	$ 1,120	$ 1,414
Other current assets	6,736	3,698
	$ 7,856	$ 5,112
Liabilities to be disposed:		
Accounts payable	$ 361,939	$ 483,438
Deposits		528
Provision for future site restoration	7,000	270,000
	$ 368,939	$ 753,966

CanArgo Standard Oil Products

In September 2002, we approved a plan to sell our interest in CanArgo Standard Oil Products Limited (CSOP), a petroleum product retail business in Georgia, to finance our Georgian and Ukrainian development projects. In October 2002, we reached agreement with Westrade Alliance LLC, an unaffiliated company, to sell our wholly owned subsidiary, CanArgo Petroleum Products Limited (CPPL), which held our 50% interest in CSOP for $4,000,000 in an arms-length transaction, with legal ownership being transferred upon receipt of final payment due originally in August 2003 and subsequently extended. The total payment received in 2004 was $1,857,000 with the final payment of the consideration received by us in December 2004 at which time we transferred our ownership in CPPL to Westrade Alliance LLC. The gain recorded on disposition of subsidiary was $1,275,351.

The results of discontinued operations in respect of CSOP consisted of the following for the years ending December 31:

	2005	2004	2004
Operating Revenues	$	$	$
Income Before Income Taxes and Minority Interest			18,242
Income Taxes			
Minority Interest in Income			
Net Income from Discontinued Operation	$	$	$ 18,242

Georgian American Oil Refinery

In 2003, we approved a plan to dispose of our interest in the Georgian American Oil Refinery Limited (GAOR) as the refinery had remained closed since 2001 and neither we nor our partners could find a commercially viable option to putting the refinery back into operation. In February 2004, we reached an agreement with a local Georgian company to sell our 51% interest in GAOR for a nominal price of one US dollar and the buyers assumption of all the obligations and debts of GAOR to the State of Georgia including deferred tax liabilities of approximately $380,000. The gain recorded on disposition of GAOR was $330,923.

The results of operations of GAOR have been classified as discontinued for all periods presented. The minority interest related to GAOR has not been reclassified for any of the periods presented, however net income from discontinued operations is disclosed net of taxes and minority interest. During 2003, a debit balance of $1,274,895 in minority interest was written-off due to a change in the intentions of our minority interest owner and a plan to dispose of the asset. The plan to dispose of the asset also led to the write-off of an inter-company payable relating to oil sales purchased from Ninotsminda Oil Company Limited. These items have been respectively recorded in impairment of other assets and other income (expense) components of continuing operations.

The results of discontinued operations in respect of GAOR consisted of the following for the years ending December 31:

	2006	2005	2004
Operating Revenues	$	$	$
Income (Loss) Before Income Taxes and Minority Interest			
Minority Interest in Loss			523,968
Net Income from Discontinued Operation	$	$	$ 523,968

3-megawatt duel fuel power generator

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In 2003, we signed a sales agreement disposing of a 3-megawatt duel fuel power generator for $600,000 and have received a non-refundable deposit of approximately $300,000. The unit was shipped to the United States where it underwent tests in late 2004. On completion of these tests to the satisfaction of the buyer, we were to transfer title for this equipment and receive the final payment of $300,000. Although the unit was successfully tested, the buyer failed to meet the sale contract terms resulting in the loss of its deposit in the third quarter, 2005.

We are currently remarketing the generator and it was impaired by $600,000 to nil in the fourth quarter of 2006 as no prospective buyer has yet been identified. The generator was classified in Assets held for sale as of December 31, 2005.

Gross consolidated assets in respect of the generator included in assets held for sale consisted of the following at December 31:

	2006	2005
Assets held for sale:		
Capital assets, net	$	$ 600,000
	$	$ 600,000

NOTE 21 SEGMENT AND GEOGRAPHICAL DATA

During the year ended December 31, 2004 CanArgo disposed of its downstream activities in Georgia and all operations outside of Georgia.

As of December 31, 2004 Georgia represented the only geographical segment.

During the year ended December 31, 2006 CanArgo s continuing operations operated through one business segment, oil and gas exploration.

Operating revenues from continuing operations for the years ended December 31 by geographical area were as follows:

	2006	2005
Oil and Gas Exploration, Development And Production		
Georgia	$ 6,526,660	$ 5,278,912
Republic of Kazakhstan		
Total	$ 6,526,660	$ 5,278,912

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Operating (loss) income from continuing operations for the years ended December 31 by geographical area was as follows:

	2006	2005
Oil and Gas Exploration, Development And Production		
Georgia	$ (36,964,155)	$ 1,168,652
Republic of Kazakhstan	(5,117,924)	(729,179)
Corporate and Other Expenses	(11,554,528)	(12,183,705)
Total Operating Loss	$ (53,636,607)	$ (11,744,232)

Net (loss) income from continuing operations for the year ended December 31, 2006 by geographical area was as follows:

	2006	2005
Oil and Gas Exploration, Development And Production		
Georgia	$ (36,964,155)	$ 1,168,652
Republic of Kazakhstan	(5,117,924)	(729,179)
Corporate and Other Expenses	(19,131,575)	(13,377,957)
Loss from Continuing Operations	$ (61,213,654)	$ (12,938,484)

Identifiable assets of continuing and discontinued operations as of December 31, 2006 and 2005, by business segment and geographical area were as follows:

	2006	2005
Corporate		
Georgia	$ 452,500	$ 785,607
Republic of Kazakhstan		
Western Europe (principally cash)	26,223,040	27,730,478
Total Corporate	26,675,540	28,516,085
Oil and Gas Exploration, Development and Production		
Georgia	87,232,064	106,905,403
Republic of Kazakhstan	22,577,878	11,426,813
Assets Held for Sale		
Western Europe		600,000
Total Identifiable Assets	$ 136,485,482	$ 147,448,301

NOTE 22 SUPPLEMENTAL CASH FLOW INFORMATION

	2006	2005	2004
Non-cash transactions:			
Stock compensation expense	$ 1,924,076	$ 2,374,578	$1,395,035
Interest expense and amortization of debt discount	3,898,091	1,277,878	653,313
Non cash miscellaneous expense Financing fees		193,000	
Debt extinguishment expense			349,923
Issuance of common stock for services		53,600	118,400
Issuance of common stock to buy out minority shareholders in CanArgo Norio			4,320,000
Issuance of common stock pursuant to SEDA (1)		10,327,305	331,182
Issuance of common stock for Consultancy agreement (Europa Oil Services Ltd) to acquire interest in Samgori			3,880,000
Issuance of common stock to acquire 55% remaining interest in Tethys Petroleum Investments, Ltd		8,360,000	
Impairment of oil and gas ventures and other assets	39,000,000		
(1) The amount recorded in 2005 included the following			
Repayment of principal of $1.5million Cornell advance from 2004		1,500,000	
Repayment of principal of $15million Cornell promissory note from 2005		7,800,000	
Payment of offering costs with proceeds from SEDA		994,757	
Payment of interest on the $1.5million Cornell advance from 2004		32,548	
		10,327,305	
There was no cash for income taxes for the years ended December 31, 2006, 2005 and 2004.			
Reclassification temporary equity		1,396,250	723,200
Cash paid for interest expense	3,594,985	621,644	11,559

NOTE 23 STOCK-BASED COMPENSATION PLANS

At December 31, 2006, stock options and warrants had been issued from the following stock based compensation plans:

<u>1995 Long-Term Incentive Plan (1995 Plan</u>). The 1995 Plan was approved by our stockholders at the annual meeting of stockholders held on February 6, 1996.This Plan allows for up to 7,500,000 shares of the Company s common stock to be issued to officers, directors, employees, consultants and advisors pursuant to the grant of stock based awards, including qualified and non-qualified stock, options, restricted stock, stock appreciation rights and other stock based performance awards. As of December 31, 2006, options to acquire an aggregate of 1,234,000 shares of common stock had been granted under this Plan and were outstanding all of which are 100% vested. The Plan expired on November 13, 2005. The awards have a term of 5 years from date of issue and vest immediately.

The Amended and Restated CanArgo Energy Inc. Plan (the CEI Plan). The CEI Plan (also known as the CAOG Plan) was adopted by the Company s Board of Directors on September 29, 1998. All

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Options outstanding under the Plan as of July 15, 1998 were assumed by the Company pursuant to the terms of an Amended and Restated Combination Agreement between the Company and CanArgo Energy Inc. dated February 2, 1998 which was approved by the Company s stockholders on July 8, 1998. This Plan allowed for up to 1,250,000 shares (of which only 988,000 shares were registered) of the Company s common stock to be issued to any director or full-time employee of the Company or a subsidiary of the Company. As of December 31, 2006, five year options to acquire an aggregate of 220,000 shares of common stock had been granted under this Plan and were outstanding of which 145,000 are currently 100% vested. The awards have a term of 5 years from date of issue, each award having a special vesting provision defined in the award.

Special Stock Options and Warrants. This plan was created to allow the Company to retain and provide incentives to existing executive officers and directors and to allow retirement of new officers and directors following the Company s decision to relocate finance and administration functions from Calgary, Canada to London, England. As of December 31, 2006, special stock options and warrants issued under this plan exercisable for an aggregate of 535,000 shares were outstanding, subject to customary anti-dilution adjustments, of which 100% were fully vested.. The awards have a term of 5 years from date of issue, each award having a vesting provision defined in the award.

2004 Long Term Stock Incentive Plan (2004 Plan). The 2004 Plan was approved by our stockholders at the annual meeting of stockholders held on May 18, 2004. This Plan allows for up to 17,500,000 shares of the Company s common stock to be issued to officers, directors, employees, consultants and advisors pursuant to the grant of stock based awards, including qualified and non-qualified stock options, restricted stock, stock appreciation rights and other stock based performance awards. As of December 31, 2006, seven year options to acquire an aggregate of 7,642,000 shares of common stock had been granted under this Plan and were outstanding, 6,544,000 of which vested at that date. The 2004 Plan will expire on May 17, 2014, although the Board of Directors may terminate the 2004 Plan at any time prior to that date. The awards have a term of 7 years from date of issue and vest 1/3 for each year, with the first 1/3 vesting immediately.

The purpose of the Company s stock option plans is to further the interest of the Company by enabling officers, directors, employees, consultants and advisors of the Company to acquire an interest in the Company by ownership of its stock through the exercise of stock options and stock appreciation rights granted under its various stock option plans.

A summary of the status of stock options granted under the Company s plans are as follows:

	Shares Issuable Under Outstanding Options	Weighted Average Exercise Price
Balance, January 1, 2004	7,986,167	0.26
Options (1995 Plan):		
Granted at market	1,005,000	0.73
Exercised	(3,120,667)	0.14
Expired		
CAOG Plan Authorization:		
Granted at market	205,000	0.60
Exercised	(399,000)	0.10
Expired		

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	Shares Issuable Under Outstanding Options	Weighted Average Exercise Price
Special Stock options and warrants:		
Increase in shares available for issue		
Granted at market		
Exercised	(291,667)	0.10
Expired		
Options (2004 Plan):		
Increase in shares available for issue		
Granted at market	5,088,000	0.65
Exercised		
Expired		
Balance, December 31, 2004	10,472,833	0.56
Options (1995 Plan):		
Granted at market		
Exercised	(1,477,500)	0.13
Expired		
CAOG Plan Authorization:		
Granted at market		
Exercised	(305,000)	0.22
Expired		
Special Stock options and warrants:		
Increase in shares available for issue		
Granted at market		
Exercised	(1,118,333)	0.83
Expired	(275,000)	1.44
Options (2004 Plan):		
Increase in shares available for issue		
Granted at market	3,129,000	1.03
Exercised	(381,000)	0.65
Expired		
Balance, December 31, 2005	10,045,000	0.72
Options (1995 Plan):		
Granted at market		
Exercised	(220,000)	0.65
Expired		

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	Shares Issuable Under Outstanding Options	Weighted Average Exercise Price
Options (2004 Plan):		
Increase in shares available for issue		
Granted at market	420,000	1.03
Exercised	(554,000)	0.79
Expired	(60,000)	1.00
Balance, December 31, 2006	9,631,000	0.73

Shares issuable upon exercise of vested options and the corresponding weighted average exercise price are as follows:

	Shares Issuable Under Exercisable Options	Weighted Average Exercise Price
December 31, 2004	6,480,833	$ 0.49
December 31, 2005	5,938,000	$ 0.63
December 31, 2006	8,458,000	$ 0.68

The weighted average fair value of options granted during the year was $1.03, $0.83 and $0.53 for the years ended December 31, 2006, 2005 and 2004 respectively.

The number and weighted average grant-date fair value of non-vested options as at January 1, 2006 was 4,147,000 and $0.68 respectively. The number and weighted average grant-date fair value of options vested during 2006 was 3,249,000 and $0.64 respectively. The number and weighted average grant-date fair value of non-vested options as at December 31, 2006 was 1,173,000 and $0.81 respectively.

The total intrinsic value of options exercised during each of the years ended December 31, 2006, 2005 and 2004 were $389,320, $3,056,721 and $3,617,089 respectively.

As of December 31, 2006 total compensation cost related to non-vested options not yet recognized is $616,723 and this cost will be recognized over a weighted average period of 9 months.

We received cash proceeds of $589,100 from the exercise of options during the year ended December 31, 2006. All share options plans are approved by the shareholders and a registration statement is subsequently filed with the SEC resulting in the issue of new shares by the company when options are exercised.

We used the black-scholes option pricing model using the following assumptions to determine the fair value of the options issued under our plans during the following years:

	2006	2005	2004
Stock price on date of grant	$ 0.91	$ 0.97	$ 0.63
Risk free rate of interest	4.88%	4.16%	3.65%
Expected life of warrant-months	84	84	82
Dividend rate	0%	0%	0%
Historical volatility	94.43%	109.49%	104.94%

The numbers above reflect the weighted average for the options issued during the year.

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The following table summarizes information about stock options outstanding at December 31, 2006:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Shares Outstanding at December 31, 2006	Weighted Average Remaining Term	Weighted Average Exercise Price	Number Of Shares Exercisable at December 31, 2006	Weighted Average Exercise Price
$0.10 to $0.14	1,120,000	1.18	0.10	1,120,000	0.10
$0.15 to $0.69	5,072,000	4.68	0.65	4,997,000	0.64
$0.70 to $1.47	3,439,000	5.50	1.04	2,341,000	1.04
$0.10 to $1.47	9,631,000	4.57	0.73	8,458,000	0.68

The following table summarizes additional information about stock options outstanding at December 31, 2006:

Range of Exercise Prices	Options Outstanding Aggregate Intrinsic Value of Shares Outstanding at December 31, 2006	Options Exercisable Aggregate Intrinsic Value Of Shares Exercisable at December 31, 2006
$0.10 to $0.14	1,701,600	1,701,600
$0.15 to $0.69	4,930,202	4,857,299
$0.70 to $1.47	2,060,080	1,402,340
$0.10 to $1.47	8,691,882	7,961,239

NOTE 24 RELATED PARTY TRANSACTIONS

A company owned by key employees of Georgian British Oil Company Ninotsminda until February 2005 and the same employees of CanArgo Georgia Limited from February 1, 2005 provided certain equipment, office and storage space to Georgian British Oil Company Ninotsminda until February 2005 and to CanArgo Georgia Limited from February 1, 2005. Total rental payments for this equipment, office and storage space in 2006 were $216,810 ($281,024 and $107,946 in 2005 and 2004 respectively). In 2004, the same company provided additional services to Georgian British Oil Company Ninotsminda in accordance with a farm-in agreement in respect of the Manavi well for the value of $450,000. No additional services were provided in 2006 and 2005.

Of the 50% of CanArgo Standard Oil Products Limited not held by CanArgo prior to its disposal in December, 2004, 41.65% was held by Standard Oil Products, an unrelated third party entity, and 8.35% held by an individual, Mr Levan Pkhakadze, who is one of the founders of Standard Oil Products and is an officer and director of CanArgo Standard Oil Products. The majority of refined product purchased by CanArgo Standard Oil Products for resale at its petrol stations is purchased from a company controlled by Standard Oil Products who together with and an individual shareholder, own the 50% interest in CanArgo Standard Oil Products not held by CanArgo.

Dr. David Robson, Chief Executive Officer, provides all of his services to CanArgo through Vazon Energy Limited of which he is the sole owner and Managing Director. In addition management services agreements exists between CanArgo and Vazon Energy whereby the services of Dr. Robson and Mrs. Landles (Corporate Secretary & Executive Vice President) and for part of the year Mr. Battey (former Chief Financial Officer), amongst others, are provided to CanArgo. Approximately $1,150,000 was paid to Vazon in respect of these services which included flow through costs for employees and consultants.

On June 7, 2005, CanArgo made an offer to acquire 55% of the ordinary share capital of Tethys which was held by Provincial and Vando for consideration of 11,000,000 CanArgo common shares. On June 9, 2005 CanArgo issued 5,500,000 shares to Provincial, of which Russell Hammond (one of our non-executive directors) is Investment Advisor in connection with this transaction.

Mr. Russell Hammond, a non-executive director of CanArgo, is also an Investment Advisor to Provincial Securities Limited who became a minority shareholder in the Norio and North Kumisi Production Sharing Agreement through a farm-in agreement to the Norio MK72 well. On September 4, 2003 we concluded a deal to purchase Provincial Securities Limited s minority interest in CanArgo Norio Limited by a share swap for shares in CanArgo. Provincial Securities Limited received 2,234,719 shares of CanArgo common stock in relation to the transaction (see Note 14). Provincial Securities Limited also had an interest in Tethys Petroleum Investments Limited which was sold in June 2005 to us by a share exchange for shares in CanArgo. Provincial Securities Limited received 5,500,000 shares of CanArgo common stock in relation to the transaction, Transactions with affiliates or other related parties including management of affiliates are to be undertaken on the same basis as third party arms-length transactions.

Transactions with affiliates are reviewed and voted on solely by non-interested members of the board of directors.

NOTE 25 SUBSEQUENT EVENTS

Tethys Financing

In February 2007 we announced that Tethys had completed a private placement with a limited group of private investors raising gross proceeds of approximately $17.35 million, by issuing in total approximately 34.7 million new ordinary shares in Tethys, these representing approximately 33% of the issued and outstanding share capital of Tethys, and with us retaining our 70,000,000 shares in Tethys, these representing the remaining 67%. Under the terms of the Shareholders Agreement entered into with the new private investors, Tethys is subject to certain positive and negative covenants which require the consent of the holders of not less than 75% of the ordinary shares in issue in Tethys from time to time (the Shareholder Majority). The Agreement also outlines certain provisions in relation to the conduct of the Tethys business and provided that the intention of Tethys, CanArgo Limited and the Investors is to use their reasonable endeavors to work towards a listing of Tethys as soon as practicable, subject to (i) the financial and commercial circumstances of Tethys, and the pre-money valuation of Tethys prior to the listing being acceptable to the Shareholder Majority; and (ii) the terms and amounts (if any) raised by Tethys on such listing being acceptable to the board of Tethys.

Tethys has now entered into an Engagement Letter with Jennings Capital Inc. of Calgary, Alberta (JCI) engaging JCI to act as lead agent with respect to a planned initial public offering (IPO) and listing of Tethys on the Toronto Stock Exchange (TSX) later this year. In addition McDaniel and Associates Consultants Limited have been engaged to carry out an independent evaluation of Tethys projects in connection with the proposed listing. The full details of the planned IPO have yet to be finalised.

Agreement has now also been reached whereby, subject to any required Kazakh regulatory approvals Tethys, through its wholly owned subsidiary Tethys Kazakhstan Limited (TKL) will acquire the 30% of BNM it does not own in return for 30 million shares in Tethys, and making BNM a wholly owned subsidiary of TKL. TKL s interest in BNM is currently the principal asset of Tethys. Following this share swap there will be approximately 134.7 million shares in Tethys of which CanArgo will own 70 million (52 %).

In February 2007 we also announced that Tethys has signed a Protocol of Intent (the `Protocol`) with the Ministry of Energy of the Republic of Tajikistan and the State Committee for Investments and Property Management of the Republic of Tajikistan giving Tethys the exclusive right to carry out technical evaluations and negotiations with the aim of entering into a contractual arrangement: to carry out oil and gas exploration activities in the Kulibsky region of Southern Tajikistan; to consider involvement in the Alimtai prospect in that region; and to consider co-operation in increasing production on currently operating fields in Tajikistan. A phase of data collection, interpretation and negotiation is planned over the next six months, with the aim of concluding basic agreements during this period.

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NOTE 26 QUARTERLY FINANCIAL DATA (Unaudited)

	2006 First Quarter	2006 Second Quarter	2006 Third Quarter	2006 Fourth Quarter
Operating revenue from continuing operations	$ 698,945	$ 1,303,132	$ 2,090,147	$ 2,434,436
Operating income (loss) from continuing operations	(3,714,741)	(3,254,124)	(3,492,195)	(43,175,547)
Net income (loss) from continuing operations	(5,536,901)	(3,408,850)	(5,699,963)	(46,567,940)
Net income (loss) from discontinued operations, net of taxes	77,759	703,814	(18,154)	(90,616)
Net income (loss)	(5,459,142)	(2,705,036)	(5,718,117)	(46,658,556)
Net income (loss) per common share - basic and diluted from continuing operations	(0.02)	(0.02)	(0.03)	(0.20)
Net income (loss) per common share - basic and diluted from discontinued operations				
Net income (loss) per common share - basic and diluted	(0.02)	(0.01)	(0.03)	(0.20)

	2005 First Quarter	2005 Second Quarter	2005 Third Quarter	2005 Fourth Quarter
Operating revenue from continuing operations	$ 608,270	$ 741,922	$ 2,580,847	$ 1,347,873
Operating income (Loss) from continuing operations	(2,658,866)	(2,375,199)	(2,527,008)	(4,183,159)
Net income (loss) from continuing operations	(2,881,448)	(2,432,750)	(2,802,340)	(4,821,946)
Net income (loss) from discontinued operations, net of taxes	407,972	176,267	(139,590)	158,521
Net income (loss)	(2,473,476)	(2,256,483)	(2,941,930)	(4,663,425)
Net income (loss) per common share - basic and diluted from Continuing operations	(0.01)	(0.01)	(0.01)	(0.02)
Net income (loss) per common share - basic and diluted from discontinued operations				
Net income (loss) per common share - basic and diluted	(0.01))	(0.01)	(0.01)	(0.02)

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NOTE 26 SUPPLEMENTAL OIL AND GAS DISCLOSURE (Unaudited)

ESTIMATED NET QUANTITIES OF OIL AND GAS RESERVES

Users of this information should be aware that the process of estimating quantities of proved and proved developed natural gas and crude oil reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved reserves are estimated quantities of natural gas, crude oil and condensate that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs with existing equipment under existing economic and operating conditions.

Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and under existing economic and operating conditions.

Oil and gas reserves

The following tables set forth our net proved oil and gas reserves, including the changes therein, and net proved developed reserves at December 31, 2006, as estimated by the independent petroleum engineering firm, Oilfield Production Consultants Limited for Georgia:

Net Proved Developed and Undeveloped Reserves Oil (In Thousands of Barrels):

	2006	2005	2004
January 1	3,514	4,076	4,395
Purchase of properties			
Revisions of previous estimates	(1,198)	(410)	(76)
Extension, discoveries, other additions			
Production	(120)	(152)	(243)
Disposition of properties			
December 31	2,196	3,514	4,076
Net Proved Developed Oil Reserves - December 31, 2006	1,647		

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Net Proved Developed and Undeveloped Reserves Gas (In Million Cubic Feet) Georgia

	2006	2005	2004
January 1	1,599	1,703	1,941
Purchase of properties			
Revisions of previous estimates	709		(66)
Extension, discoveries, other additions			
Production	(483)	(104)	(172)
Disposition of properties			
December 31	1,825	1,599	1,703
Net Proved Developed Gas Reserves - December 31, 2006	1,225		

Net proved oil reserves in Georgia consisted of the following at December 31:

	2006		2005	
	Oil Reserves Gross (MSTB)	PSC Entitlement Volumes (MSTB) (1)	Oil Reserves Gross (MSTB)	PSC Entitlement Volumes (MSTB) (1)
Proved Developed Producing	1,811	1,177	3,151	2,013
Proved Undeveloped	1,568	1,019	2,348	1,501
Total Proven	3,379	2,196	5,499	3,514

Net proved gas reserves in Georgia consisted of the following at December 31:

	2006		2005	
	Gas Reserves Gross (MMCF)	PSC Entitlement Volumes (MMCF) (1)	Gas Reserves Gross (MMCF)	PSC Entitlement Volumes (MMCF) (1)
Proved Developed Producing	1,885	1,225	1,343	858
Proved Undeveloped	923	600	1,159	741
Total Proven	2,808	1,825	2,502	1,599

(1) PSC Entitlement Volumes

attributed to CanArgo are calculated using the economic interest method applied to the terms of the production sharing contract. PSC Entitlement Volumes are those produced volumes which, through the production sharing contract, accrue to the benefit of Ninotsminda Oil Company after deduction of Georgian Oil s share which includes all Georgian taxes, levies and duties. As a result of CanArgo s interest in Ninotsminda Oil Company, these volumes accrue to the benefit of CanArgo for the recovery of capital, repayment of operating costs and share of profit.

The following tables set forth our net proved oil and gas reserves, including the changes therein, and net proved developed reserves at December 31, 2006, as estimated by the independent petroleum engineering firm, Oilfield Production Consultants Limited for Kazakhstan:

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Republic of Kazakhstan

Net Proved Developed and Undeveloped Reserves Gas (In Million Cubic Feet) Kazakhstan

	2006	2005 (1)	2004
January 1	32,694		
Purchase of properties		29,699	
Revisions of previous estimates	(2,354)		
Extension, discoveries, other additions		2,995	
Production			
Disposition of properties			
December 31	30,340	32,694	

Net Proved Developed Gas Reserves - December 31, 2006

Net proved gas reserves in the Kazakhstan consisted of the following at December 31:

	2006		2005 (1)	
	Gas Reserves Gross (MMCF)	PSC Entitlement Volumes (MMCF) (2)	Gas Reserves Gross (MMCF)	PSC Entitlement Volumes (MMCF)
Proved Developed Producing				
Proved Undeveloped	30,340	30,340	32,694	32,694
Total Proven	30,340	30,340	32,694	32,694

(1) On June 9, 2005 we acquired 100% ownership of Tethys Petroleum Investments Limited (TPI) and as at 31 December 2005, this entity is now consolidated in our financial statements. TPI through its 100% owned Kazakhstan

subsidiary TKL (Tethys Kazakhstan Limited), holds 70% ownership rights in BN Munai LLP, a Kazakh registered company that has the 100% rights to the Kyzyloi field. Prior to the company s 100% ownership, we chose to use our equity ownership percentage as the basis for recording our portion of our investees loss. No reserves were assessed before we owned 100% of TPI.

(2) TPI through its 100% owned Kazakhstan subsidiary TKL, holds 70% ownership rights in BN Munai LLP, a Kazakh registered company that has the 100% rights to the Kyzyloi field. Under a loan agreement with BN Munai LLP, TKL will take 100% of the net cash flow of the Kyzyloi development until its loan is repaid. This loan

is currently in excess of net cash flows generated from the production of gross proven reserves.

Results of continuing operations for oil and gas producing activities

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Results of continuing operations for oil and gas producing activities, all in Georgia, for 2006, 2005 and 2004 are as follows:

Year Ended December 31, 2006	Eastern Europe
Revenues	$ 6,526,660
Operating expenses	1,702,679
Depreciation, depletion and amortization	3,388,134
Impairment of oil and gas properties	38,400,000
Operating Income (Loss)	(36,964,153)
Income tax provision	
Results of Continuing Operations for Oil and Gas Producing Activities	$ (36,964,153)

Year Ended December 31, 2005	Eastern Europe
Revenues	$ 5,278,912
Operating expenses	1,109,588
Depreciation, depletion and amortization	2,651,053
Impairment of oil and gas properties	
Operating Income (Loss)	1,518,271
Income tax provision	
Results of Operations for Oil and Gas Producing Activities	$ 1,518,271

Year Ended December 31, 2004	Eastern Europe
Revenues	$ 7.832.894
Operating expenses	1,829,058
Depreciation, depletion and amortization	2,298,218
Impairment of oil and gas properties	
Operating Income (Loss)	3,705,618
Income tax provision	
Results of Operations for Oil and Gas Producing Activities	$ 3,705,618

Georgia was the only country where we had oil and gas producing activities for 2006, 2005 and 2004. Although we have Proved Undeveloped reserves in Kazakhstan as at December 31, 2006, we have not yet completed the infrastructure to produce these reserves.

Costs incurred for oil and gas property acquisition, exploration and development activities

Costs incurred for oil and gas property acquisition, exploration and development activities for 2006, 2005 and 2004 are as follows:

Year Ended December 31, 2006		Eastern Europe
Property Acquisition		
Unproved (2)		
Proved		
Exploration		25,537,532
Development		9,714,980
Total costs incurred	$	35,252,512

Year Ended December 31, 2005		Eastern Europe (1)
Property Acquisition		
Unproved (2)	$	9,408,644
Proved		1,034,294
Exploration		16,133,410
Development		20,959,051
Total costs incurred	$	47,535,399

Year Ended December 31, 2004		Eastern Europe
Property Acquisition		
Unproved (2)	$	3,416,900
Proved		3,880,000
Exploration		1,757,010
Development		6,588,137
Total costs incurred	$	15,642,047

(1) On June 9, 2005 we acquired 100% ownership of Tethys Petroleum Investments Limited (TPI) and this entity as at 31 December 2005, is now

consolidated in our financial statements. TPI through its 100% owned Kazakhstan subsidiary TKL (Tethys Kazakhstan Limited), holds 70% ownership rights in BN Munai LLP, a Kazakh registered company that has the 100% rights to the Kyzyloi field. Prior to 100% ownership, we chose to use our equity ownership percentage as the basis for recording our portion of our investees loss.

(2) These amounts represent costs incurred by CanArgo and excluded from the amortization base until proved reserves are established or impairment is determined.

Aggregate Capitalized Costs

Capitalized costs relating to Oil and Gas Activities is as follows:

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December 31, 2006 (in thousands)	Georgia	Republic of Kazakhstan
Proved	$ 53,679	$ 9,183
Unproved	55,097	13,216
Total capitalized Costs	108,776	22,399
Accumulated depreciation, depletion and amortization	(29,208)	
Net capitalized costs	$ 79,568	22,399

December 31, 2005 (in thousands)	Georgia	Republic of Kazakhstan
Proved	$ 81,555	$ 1,897
Unproved	41,115	9,530
Total capitalized Costs	122,670	11,427
Accumulated depreciation, depletion and amortization	(26,034)	
Net capitalized costs	$ 96,636	11,427

(1) On June 9, 2005 we acquired 100% ownership of Tethys Petroleum Investments Limited (TPI) and as at December 31, 2005 this entity is now consolidated in our financial statements. TPI through its 100% owned Kazakhstan

subsidiary TKL (Tethys Kazakhstan Limited), holds 70% ownership rights in BN Munai LLP, a Kazakh registered company that has the 100% rights to the Kyzyloi field. Prior to 100% ownership, we chose to use our equity ownership percentage as the basis for recording our portion of our investees loss.

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.

CanArgo 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.

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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 expenses 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 carryforwards. Use of a 10% discount rate is required by SFAS No. 69.

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.

Standardized measure of discounted future net cash flows relating to proved oil and gas reserves

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

December 31, 2006 (in thousands)	Georgia	Republic of Kazakhstan
Future cash inflows	$ 110,443	$ 25,382
Less related future:		
Production costs	28,668	2,580
Development and abandonment costs	7,120	5,888
Future net cash flows before income taxes	74,655	16,914
Future income taxes	(4,091)	(4,392)
Future net cash flows (1)	70,564	12,522
10% annual discount for estimating timing of cash flows	(37,419)	(3,162)
Standardized measure of discounted future net cash flows	$ 33,145	$ 9,360

December 31, 2005 (in thousands)	Georgia	Republic of Kazakhstan (2)
Future cash inflows	$ 179,340	$ 27,180
Less related future:		
Production costs	26,406	3,060
Development and abandonment costs	18,808	11,000
Future net cash flows before income taxes	134,126	13,120
Future income taxes	(6,567)	(7,220)
Future net cash flows (1)	127,559	5,900
10% annual discount for estimating timing of cash flows	51,056	2,733

Standardized measure of discounted future net cash flows	$ 76,503	$ 3,167

(1) In Georgia, future cash flows are based on PSC Entitlement Volumes attributed to CanArgo using the economic interest method applied to the terms of the production sharing contract. PSC Entitlement Volumes are those produced volumes which, through the production sharing contract, accrue to the

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benefit of Ninotsminda Oil Company Limited after deduction of Georgian Oil s share which includes all Georgian taxes, levies and duties. As a result of our interest in Ninotsminda Oil Company Limited, these volumes accrue to the benefit of CanArgo for the recovery of capital, repayment of operating costs and share of profit.

In Kazakhstan, Tethys Petroleum Investment Limited (TPI) through its 100% owned Kazakhstan subsidiary TKL (Tethys Kazakhstan Limited), holds 70% ownership rights in BN Munai LLP, a Kazakh registered company that has the 100% rights to the Kyzyloi field. Under a loan agreement with

BN Munai LLP, TKL will take 100% of the net cash flow of the Kyzyloi development until its loan is repaid. This loan is currently in excess of the net cash flows forecast to be generated from the production of gross proven reserves.

(2) On June 9, 2005 we acquired 100% ownership of Tethys Petroleum Investments Limited (TPI) and as at December 31, 2005 this entity is now consolidated in our financial statements. TPI through its 100% owned Kazakhstan subsidiary TKL (Tethys Kazakhstan Limited), holds 70% ownership rights in BN Munai LLP, a Kazakh registered company that has the 100% rights to the Kyzyloi field. Prior to 100% ownership, we chose to use our

equity
ownership
percentage as
the basis for
recording our
portion of our
investees loss.

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

	December 31		
In Thousands	2006	2005	2004
Beginning of year	$ 76,502	$ 46,411	$ 37,530
Purchase (sale) of reserves in place			
Revisions of previous estimates	(38,635)	(13,209)	(4,251)
Development costs incurred during the period	(9,689)	27,437	6,588
Additions to proved reserves resulting from Extensions, discoveries and improved Recovery			
Accretion of discount	7,650	4,641	1
Sales of oil and gas, net of production costs	4,824	(3,495)	(6,004)
Net change in sales prices, net of Production costs	(8,269)	56,113	18,057
Changes in production rates (timing) and other	761	(41,396)	(5,510)
Net increase (decrease)	(43,358)	30,091	8,881
End of year	$ 33,144	$ 76,502	$ 46,411

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

	December 31		
In Thousands	2006	2005 (1)	2004
Beginning of year	$ 3,167	$	$
Purchase (sale) of reserves in place		2,644	
Revisions of previous estimates	(1,383)	523	
Development costs incurred during the period	2,604		
Additions to proved reserves resulting from Extensions, discoveries and improved Recovery			
Accretion of discount	317		
Sales of oil and gas, net of production costs			
Net change in sales prices, net of Production costs			
Changes in production rates (timing) and other	(4,527)		
Net increase (decrease)	(2,989)	3,167	
End of year	178	$ 3,167	$

(1) On June 9, 2005 we acquired 100% ownership of Tethys Petroleum Investments Limited (TPI) and as at 31 December 2005, this entity is now consolidated in our financial statements. TPI through its 100% owned Kazakhstan subsidiary TKL (Tethys Kazakhstan Limited), holds 70% ownership rights in BN Munai LLP, a

Kazakh registered company that has the 100% rights to the Kyzyloi field. Prior to 100% ownership, we chose to use our equity ownership percentage as the basis for recording our portion of our investees loss. No reserves were assessed before we owned 100% of TPI.