CANARGO ENERGY CORP
Form 10-K
March 16, 2006

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, 2005

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

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 was approximately $248 million as of 10 March 2006, based upon the last reported sales price of such stock on The American Stock Exchange on that date. For this purpose, the Registrant considers Dr. David Robson, Vincent McDonnell, Michael Ayre, Russ Hammond and Nils Trulsvik to be its only affiliates.

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, 224,108,606 shares outstanding as of 10 March, 2006.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant s definitive Proxy Statement issued in connection with its 2006 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 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.

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.

MCM One thousand cubic meters of natural gas.

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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. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0303. The SEC maintains an internet site at www.sec.gov that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC. 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. 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 appraisal 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 (PSC), 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 December 2006;

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});

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 381,034 acres (1,542 Km^{2}), however, it is subject to a 25% relinquishment in March 2006;

4. The Block XI^{G} and XI^{H} Production Sharing Contract (Tbilisi PSC), in which CanArgo Norio Limited owns a 100% interest. This PSC covers an area of approximately 119,845 acres (485 Km^{2}).

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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. CanArgo Samgori Limited is a wholly owned subsidiary of CanArgo. This PSC covers an area of approximately 156,664 acres (634 Km^2) of which 50%, excluding any development area, was subject to relinquishment by September 2006.

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 Investments Limited 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. The Kyzyloi Gas Field Production Contract covers an area of 70,919 acres (287 Km^2) and is surrounded by the 411,922 acres (1,667 Km^2) Akkulka Exploration Contract area. In November 2005, BNM acquired a 100% interest in the Greater Akkulka Exploration Contract. This contact, which is for a period of 25 years, with an initial six year exploration period covers an area of approximately 2.75 million acres (11,133Km^2) surrounding the Akkulka area. On the Greater Akkulka Exploration Contract, 20% of the area is to be relinquished at the end of the second year (November 23, 2007) with 20% annually thereafter up to the end of the original six year contract.

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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 and in which we acquired an interest in early 2004 (we withdrew from this interest in 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 nine are currently producing. A total of 144 wells have been drilled in the Samgori Field area which includes a complex of three separate oil accumulations namely Samgori, South Dome and Patardzeuli.

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

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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).

Other Projects

We have additional exploratory and developmental oil and gas properties and prospects in Georgia and Kazakhstan. During 2004, 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 2006 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 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. 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.

The Samgori PSC came into effect on September 1, 2001 and extends for an initial period of twenty years with the final year of the contract being September 1, 2021 this period may be extended subject to commercial production being available for up to a further fifteen years until 2036.

The original Contractor party to the Samgori PSC, National Petroleum Limited (NPL), had an option to reacquire its Contractor s interest in the Samgori PSC and its 50% interest in the operating company in the event that the agreed work program was not completed in part (which involves the drilling of two horizontal well sections) by September 16, 2006 and completed in full by June 2008. NPL has outstanding costs and expenses of $37,528,964 in relation to the Samgori PSC which are recoverable by NPL receiving 30% of annual net profit from the Field until such costs have been fully repaid. Under the Samgori PSC, up to 50% of petroleum produced under the contract is allocated to the Contractor parties for the recovery of the cumulative allowable capital, operating and other project costs associated with the Samgori Field and exploration in Block XI ^{B} (Cost Recovery Oil). The cost recovery pool includes the $37,528,964 costs previously incurred by NPL. The balance of production (Profit Oil) is allocated on a 50/50 basis between the State and the Contractor parties respectively. While GOSL and CSL continued to have unrecovered costs, they would have received 75% of total production (net 37.5% to us). After recovery of their cumulative capital, operating and other allowable project costs including the NPL costs, the Contractor parties receive 30% of Profit Oil (net 15% to us). The allocation of a share of production to the State relieves the Contractor parties of all obligations they would otherwise have to pay the State of Georgia for taxes, duties and levies related to activities covered by the Samgori PSC. After NPL s costs were repaid from either Field production or other production in the PSC (in the event that new fields are developed in areas identified using seismic surveys originally performed by NPL), NPL were to continue to receive 5% of annual net profit.

Under the Samgori PSC, Georgian Oil as the State representative in the contract is entitled to receive up to 250,000 tons (approximately 1.6 million barrels) of oil (Base Level Oil) from a maximum of 50% per calendar quarter of production when the value of the cumulative Cost Recovery Petroleum, cumulative Profit Oil and cumulative Profit Natural Gas delivered to the Contractor parties exceeds the cumulative allowable capital, operating

and other project costs including finance costs associated with the Samgori Field and exploration in Block XI B and the NPL costs. While Base Level Oil is being delivered to Georgian Oil, the Contractor parties will continue to be entitled to a maximum of 50% of the remaining Profit Oil. The Base Level Oil is an estimate of the amount of oil that Georgian Oil would have expected to produce from the contract area had the State not come to a contractual arrangement with the previous Contractor party in 1996.

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. CSL has now been informed that, NPL have 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. The Ninotsminda Field is separated from Patardzeuli by a saddle and a NW-SE trending cross fault. The field structure comprises an elongate

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anticline which measures 10 Km (E-W) by 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 100-500mD. 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.

NOC began an immediate rehabilitation of the Ninotsminda Field in 1996 which included repairing and adding perforations to existing wells, obtaining 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, and sidetracked as a horizontal producer in 2000. The N98H well had produced approximately 413,000 barrels of oil to the end of January 2006.

As a result of this development work, subsequent drilling and the completion of a dynamic reservoir model, it

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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. In January 2003, a new horizontal sidetrack well (N4H) was successfully completed and originally put on production at over 1,000 barrels of oil per day (bopd). At the end of January 2006, this well had produced approximately 403,000 barrels of oil. Two further horizontal sidetrack wells (N100H and N96H) were successfully completed in September 2003 and in December 2003, respectively. The N100H well tested at rates of over 2,000 bopd and N96H at rates in excess of 1,200 bopd. Although all three wells were put on production at lower rates in accordance with the recommendations of independent petroleum engineering specialists, 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.

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 wellbores on the Ninotsminda and Samgori Fields. 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 including: N22H: N30H: a second horizontal well, N100H2 east horizontal, from the N100 well bore (which achieved good rates of production when drilled horizontally with conventional techniques and which was later the subject of a blow out in September 2004); N49H: N97H, and a new well (N99) designed so as to have more than one horizontal wells drilled from it. The N99 well was planned for the eastern part of the Field, an area that is currently largely undeveloped.

UBCTD operations started on the first well in the program, the N22H well, in December 2004. The well is located in the east part of the Ninotsminda 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 under balanced drilling 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 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. In this respect, we continue to investigate the potential of bringing an alternative supplier of such equipment and services to Georgia.

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. On October 27, 2005 we reached total depth (TD) on the first sidetrack, the N100H2 well. The well was completed in the Middle Eocene reservoir at approximately 8,659 feet (2,640 meters) TVD (True Vertical Depth) 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 million cubic feet

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(370,000 cubic meters) 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 horizontal section is located in the uppermost part of the oil zone, close to the gas-oil contact, and a permeable interval was encountered in the build up section within the lower part of the gas cap. It is expected that the proportion of liquid hydrocarbon production will rise over time. The well is currently choked back as we await completion of repairs by the state oil company, Georgian Oil, to the 22.4 mile (36 Km) pipeline which it is planned will deliver the gas from Ninotsminda to the local State-run thermal electricity generating station at Gardabani. Terms have been agreed with the government for a gas supply agreement from the Ninotsminda Field and it is expected that an agreement will be signed in the near future.

In November 2005, we announced that operations had commenced on the next horizontal sidetrack well on the Ninotsminda Field, N97H. This sidetrack is more complicated than the N100H2 well as it is located on the northern flank of the field and it was necessary to first sidetrack the well from a much shallower level towards the crest of the field before the horizontal section could be drilled through the reservoir in a westerly direction along the crest of the structure. The well was drilled by us using our own rig and equipment while utilising directional equipment and services provided by Baker Hughes. The well has now been completed with a 1,725 foot (534 meters) horizontal section having been drilled through the Middle Eocene reservoir where good mud losses were observed, this indicating good permeability. A 1,490 foot (454 meters) slotted production liner has been run in the horizontal section furthest from the original well bore and the well is currently being tested. Depending on the test results, it is planned to put the well on production immediately.

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

The first exploration well drilled on the Manavi structure, a large prospect at Cretaceous level, within the Ninotsminda PSC area reached total depth in September 2003. This well was the second well drilled under a Participation Agreement with AES Gardabani (a subsidiary of AES Corporation who at that time owned part of the Gardabani thermal power plant) (AES) relating to the exploration and potential future development of sub Middle Eocene gas prospects in parts of the Ninotsminda PSC. In January 2002, the first well drilled under the Participation Agreement, N100, reached a depth of 16,165 feet (4,927 meters) without having reached the targeted Cretaceous zone. The well was terminated primarily for mechanical reasons, having penetrated a significant thickness of oil bearing sandstones in the Lower Eocene and Palaeocene sequences. Three formation tests were carried out on these sandstones which recovered 35 ^{o} API (SG 0.85) oil, but without commercial flow, despite the installation of a down-hole progressive cavity pump. We have concluded that the reason for the lack of commercial flow was either that the zone suffered substantial formation damage due to the high mud weights used to drill the well, which was being drilled for a potentially high pressure Cretaceous objective, or that it was of low permeability. Potential still remains in this sequence but the N100 well was re-completed in 2003 as a Middle Eocene horizontal oil producer on the Ninotsminda Field. Under the Participation Agreement, AES was to earn a 50% interest in identified prospects at the sub Middle Eocene stratigraphic level (rocks older than the Middle Eocene sequence i.e., below the producing horizons of the Ninotsminda Field) by funding two-thirds of the cost of a three-well exploration program. However, prior to the completion of the program as defined in the Participation Agreement, AES withdrew from the Participation Agreement in February 2002 in order to focus on its core business. The Participation Agreement was terminated without AES earning any rights to any of the Ninotsminda / Manavi area reservoirs. Under a separate Letter Agreement, if gas from the sub Middle Eocene is discovered and produced from the Ninotsminda / Manavi area, AES will be entitled to recover at the rate of 15% of future gas sales from the sub Middle Eocene, net of

[1] using 6,000 cubic feet of gas = 1 barrel of

oil/condensate

operating costs, their funding under the Participation Agreement. AES also has an option to enter into a five year take or pay gas sales agreement for a quantity up to 200 million cubic meters per year at an initial contract price of $1.30 per thousand cubic feet ($46.00 per thousand cubic meters). AES has since sold its interest in the Gardabani power plant and other assets in Georgia.

The Manavi well, M11, was targeting a large Cretaceous prospect in the Manavi area, east of the Ninotsminda Field, with further potential in the Middle Eocene. This well was suspended for financial reasons in 2002, following the withdrawal of AES from the Participation Agreement, at a depth of 13,720 feet (4,182 meters), but re-started following a farm-in by a local oil service company in September 2003. This well was drilled to a total depth of 14,765 feet (4,500 meters), and encountered the Cretaceous limestone target at 14,265 feet (4,348 meters). Drilling data and wire line logs indicated the presence of hydrocarbons in the Cretaceous and a production liner was set for testing. After initially very encouraging clean-up flows of drilling fluid accompanied by good quality 34.4º API oil, and gas, flow stopped due to a mechanical collapse of the production tubing. We believe that this is the first test of oil in the Cretaceous sequence in Georgia; however, this sequence is a prolific producer in nearby Chechnya and Dagestan. Regional outcrop studies in east-central Georgia indicate that the Cretaceous be over 1,000 feet (~300 meters) thick. Although over 490 feet (150 meters) of hydrocarbons were encountered in the Manavi well, no oil-water contact was identified on the logs. An earlier well, the Manavi M7 well, drilled to the south of the M11 location in Soviet times, encountered hydrocarbons in the Cretaceous limestone sequence over 4,265 feet (1,300 meters) deeper, before this well was abandoned without testing being completed.

Mapping of the Manavi Cretaceous oil discovery indicates a substantial potential oilfield might be present. In addition, the shallower Middle Eocene sequence encountered in the well also had hydrocarbon indications, and awaits testing. This is approximately 3,280 feet (1,000 meters) deeper than the currently assumed oil-water contact for eastern Ninotsminda, and may indicate deeper oil in this area. Following the initial testing of the M11 well, CanArgo and NOC agreed with its farm-in partner GBOSC, to buy out its 50% interest in the well by issuing to GBOSC two million shares of CanArgo common stock. As such NOC has now regained its 100% interest in the well, subject only to the possible gas sales related arrangements with AES mentioned above.

Attempts to recover the damaged tubing from the M11 well were unsuccessful. The well was prepared subsequently for sidetracking and additional drilling equipment including more powerful mud pumps and bicentrical drilling bits were added to our rig for this work. Operations recommenced in December 2004 with CanArgo s modified Russian UralMash 4E rig and despite our best efforts we continued to encounter drilling problems due to the extremely over-pressured swelling clays above the reservoir intervals. After extensive technical analysis and discussions with the international drilling contractor Saipem S.p.A. (Saipem), and Baker-Hughes International (Baker-Hughes), a major drilling mud company, it was decided that the optimum way to sidetrack this well to the top of the reservoir as planned was to use an oil-based mud system (to control the swelling clays) on the Sapiem Ideco E-2100Az drilling rig (which is equipped with a top-drive drilling system and can use an oil-based mud system unlike our current UralMash rig). Service contracts were subsequently concluded with Saipem to provide a rig and drilling services to the Company and with Baker-Hughes for the provision of an oil-based mud system.

On August 26, 2005 we announced that the Manavi M11Z well had reached a total depth (TD) of 14,994 feet (4,570 meters) measured depth (MD) in the Cretaceous. 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) MD some 230 feet (70 meters) MD higher than in the original M11 well while the secondary Middle Eocene target zone was penetrated at 13,009 feet (3,965 meters) MD again significantly higher than in the M11 well. Drilling data and slim hole wireline logs indicated the presence of hydrocarbons in both the Cretaceous and Middle Eocene target zones.

On October 6, 2005 we announced that we had commenced testing operations on M11Z. A pre-perforated $2^{7/8}$ inch (73mm) liner was run in the slim hole, and the Saipem drilling rig removed from the site while CanArgo Rig #1 was mobilized to the location for testing operations. 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

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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 wellbore 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-wellbore damage is through the application of acid using coiled tubing and, if necessary, perforate. It is now planned to carry out an acid stimulation and complete the well test using a Schlumberger supplied coiled-tubing unit, pumping equipment and completion fluids. The delay in testing this well has been due to the difficulty in sourcing a coil tubing unit to Georgia.

We have identified further appraisal locations on the Manavi structure. Drilling operations at the first appraisal site, M12 using the Saipem rig commenced on February 9, 2006. 20 inch (508 mm) casing has now been set and the well is currently operating in the 17 1/2 inch (445 mm) hole section. The well is located approximately 2.5 miles (4 Km) to the west of the M11 discovery well. CanArgo rig #2 was used to spud the well and drill the surface casing section to a depth 1,302 feet (397 meters) whilst Saipem completed operations on the Norio MK72 well. M12 has a planned total depth of 15,092 feet (4,600 meters), and is expected to be completed in the summer of 2006.

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.

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 what is found in 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 is reported to have produced 1 million cubic feet 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. This prospect is located approximately 7.5 miles (12 Km) southeast of Tbilisi and is close to the 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) and is approximately 12.5 miles (20 Km) west of the Gardabani thermal power plant.

On March 3, 2006 we announced that our subsidiary, CanArgo (Nazvrevi) Limited (CNZ) has signed a Memorandum of Understanding (MOU) which includes the terms of a take-or-pay natural gas supply contract with the Ministry of Energy of Georgia relating to gas sales from the Kumisi gas prospect near Tbilisi, Georgia, (Kumisi). The MOU will become effective subject to final regulatory approval. This MOU provides the commercial basis for CNZ to move forward with the appraisal of Kumisi and, based on this, CNZ plans to spud a well on Kumisi within the Nazvrevi PSC area between May and December of 2006.

The MOU contains the terms of a take-or-pay gas supply contract 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 US$ 1.56 per mcf (US$ 55 per MCM), increasing to US$ 2.28 per mcf (US$ 80 per MCM) by the tenth contract year, after which escalation will be based on European Union heavy fuel oil price changes.

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The gas supply contract is 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.

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 STATEMENT 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.

RISKS ASSOCIATED WITH OUR BUSINESS AND BUSINESS OPERATIONS.

WE HAVE EXPERIENCED RECURRING LOSSES.

For the fiscal years ended December 31, 2005, 2004, 2003, 2002, and 2001, we recorded net losses of $12,335,314, $4,757,000, $7,322,000, $5,328,000, and $13,218,000 respectively, and have an accumulated deficit of $117,201,506 as at December 31, 2005. No impairment of oil and gas properties was recorded in 2005 or 2004. The loss in 2003 included a writedown in our carrying value of the Bugruvativske Field in Ukraine of $4,790,000 to reflect the estimated recoverable amount from disposal, a write-off of the $1,275,000 debit balance in minority interest in Georgian American Oil Refinery (GAOR) due to a change in the intentions of our minority interest owner and plan to dispose of the asset, and a generator unit was impaired by $80,000 to reflect its fair value less cost to sell. Impairments of oil and gas properties, ventures and other assets in prior years include writedowns of $1,600,000 in 2002 and $11,160,000 in 2001. No assurance can be given, however, that we will not experience operating losses or additional writedowns in the future.

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 on a basis which assumes that operating cash flows are realized and/or proceeds from additional financings and/or the sale of non-core assets are received to meet our cash flow needs. As a result of a private placement of our Senior Secured Notes due July 25, 2009 and our Senior Subordinated Convertible Guaranteed Notes due September 1, 2009, and based upon the current level of operations, we believe that, coupled with our cash flow from operations as well as the possibility, if required, of obtaining third party participation in our projects, we will have adequate capital to meet our anticipated existing requirements for working capital, capital expenditures, interest payments and scheduled principal payments for the next twelve months. However, 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 these properties will require the availability of substantial funds from internal and/or external sources. Furthermore, unanticipated investment opportunities and operational difficulties may require unscheduled capital expenditures which may, in turn, require additional fund raising. No assurance can be given that we will be able to secure such funds or, if available, such funds can be obtained on commercially reasonable terms.

OUR CURRENT OPERATIONS ARE DEPENDENT ON THE SUCCESS OF OUR GEORGIAN EXPLORATION ACTIVITIES AND OUR ACTIVITIES ON THE NINOTSMIND AND KYZYLOI FIELDS.

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. More recently we have begun operations in Kazakhstan, particularly on the Kyzyloi Gas Field. 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 or the Kyzyloi Gas 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. Furthermore, the maintenance of production levels from the Ninotsminda Field is subject to regular workover operations on the wells due to the friable nature of the reservoir and the need to remove sediment build-up from the production interval. Such operations will add additional costs and may not always be successful. 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 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

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value of the Ninotsminda Field or the Kyzyloi Gas 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.

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 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. Finally, our ability to secure debt financing is subject to certain limitations. See Our Ability To Incur Additional Indebtedness Is Restricted Under The Terms Of The Senior Secured And Subordinated Notes below.

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 in Kazakhstan, both of which are, 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. 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 an arrangement. 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 recently become more fragmented, and the economic institutions of these countries have recently converted to a market economy from a planned economy. New laws have recently 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 new 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 Georgian administration has made public statements supporting foreign investment in Georgia, and 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 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 may 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 in Georgia.

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. Since we are dependent on international operations, specifically those in Georgia

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and in Kazakhstan, 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.

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 have identified a number of material weakness in our evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2005 (see Part II, Item 9A Control and Procedures). We plan to undertake a process to remediate the identified material weaknesses; however our failure to complete this remediation process may adversely affect our ability to accurately report our financial results in a timely manner.

We also believe that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were ineffective as of December 31, 2005. We believe that the material weaknesses identified in our evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2005 mean that we cannot fully ensure that the information required to be disclosed by us in the reports we file or submit under the Exchange Act with the Commission (1) is recorded, processed, summarized and processed within the time period specified in the Commission s rules and forms and (2) is accumulated and communicated to the management, including principal executives and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

OUR ABILITY TO INCUR ADDITIONAL INDEBTEDNESS IS RESTRICTED UNDER THE TERMS OF THE SENIOR SECURED AND SUBORDINATED NOTES.

Pursuant to the terms of (i) the Note Purchase Agreement dated July, 25, 2005 entered into by and between CanArgo and the purchasers of the Senior Secured Notes due July, 25, 2009 (Senior Secured Notes) and (ii) the Note and Warrant Purchase Agreement dated March 3, 2006 entered into by and between CanArgo and the purchasers of the Senior Subordinated Convertible Guaranteed Notes due September 1, 2009 (Subordinated 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% of the outstanding principal amount of the Senior Secured Notes and 50% of the outstanding principal amount of the Subordinated Notes, or in limited permitted circumstances. The definition of indebtedness in the Note Purchase Agreement and Note and Warrant Purchase Agreement 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 the Note and Note and Warrant Purchase Agreements).

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;
- labour 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, including, without limitation:

- natural phenomena, such as bad weather;
- 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. Risks associated with bad weather apply in particular to the Kyzyloi and Akkulka areas in Kazakhstan which has extremes of winter and summer temperatures and where extremely low winter temperatures and snow may hamper and delay operations and potentially affect production. This particular risk applies to a lesser extent in Georgia, but we have experienced delays due to extreme snowfall and winter conditions and earthquakes. 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. This would apply to our projects both in Georgia and in Kazakhstan. 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

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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, Caucasus, 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 NOC 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 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;
- labour 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.

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WE FACE SIGNIFICANT COMPETITION.

The oil and gas industry 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 our current long term debt has fixed interest rates, 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. Prior to the listing on the AMEX, our stock was traded on the Over the Counter Bulletin Board in the United States and on the OSE. During the 12 months ended December 31, 2005, the average daily trading volume for our common stock on the OSE was 3,726,418 shares and 1,723,540 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 4.45 and $0.66 to a high of NOK 14.10 and $2.25 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

Not applicable.

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ITEM 2. PROPERTIES.

Production History

Ninotsminda

The Ninotsminda Field was discovered and initial development began in 1979. Current gross field production as of the end of January, 2006 was approximately 510 bopd. Gross and net production from the Ninotsminda Field for the past three years was as follows:

Year Ended December 31,	Oil (Barrels) Gross	Oil (Barrels) Net (PSC Entitlement)[1]	Gas (mcf) Gross	Gas (mcf) Net (PSC Entitlement)[1]
2005	184,952	120,219	71,241	46,307
2004	370,176	241,131	65,066	42,293
2003	695,174	451,863	108,630	70,610

(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. 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

In April 2004, we announced that we had completed our acquisition of a 50% interest in the Samgori (Block XI ^{B}) Production Sharing Contract (Samgori PSC) in Georgia in which we have since terminated our interest with effect from February 16, 2006. The gross field production as of end of January 2006 was approximately 380 bopd. The gross and net production for the past year and the nine month period ending December 31, 2005 was as follows:

Year Ended December 31,	**Oil (Barrels) Gross**	**Net (PSC Entitlement)[2]**	**CSL Net Share**
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. 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, 2005.

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Productive Wells and Acreage

The following table summarizes as of December 31, 2005, 2004 and 2003 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**
Ninotsminda Field	11	492

On December 31, 2005, 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. This information below as of December 31, 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**
Samgori Field Complex	11.5	950

Reserves

Ninotsminda Field, Georgia

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, 2006 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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Exploration and Deveopment Wells

The following table summarizes as of December 31, 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	1
Norio Field	1	
	3	1

The following table summarizes as of December 31 2005, 2004 and 2003, 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.

	2005	2004	2003
Ninotsminda Field	1	1	1
	1	1	

The following table summarizes as of December 31 2005, 2004 and 2003, 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 wells.

	2005	2004	2003
Samgori Field *	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 2005, 2004 and 2003, 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.

	2005	2004	2003
Ninotsminda Field	8	6	6
	8	6	6

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Oil Reserves	**Oil Reserves Gross (Million Barrels)**	**PSC Entitlement Volumes (1) (Million Barrels)**
Proved Developed	3.150	2.013
Proved Undeveloped	2.349	1.501
Total Proven	5.499	3.514

Gas Reserves	**Gas Reserves - Gross (Billion Cubic Feet)**	**PSC Entitlement Volumes (1) (Billion Cubic Feet)**
Proved Developed	1.343	0.858
Proved Undeveloped	1.159	0.741
Total Proven	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 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 accrue to the benefit of CanArgo for the recovery of capital, repayment of operating costs and share of profit.

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, 2006 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.

Gas Reserves	**Gas Reserves - Gross (Billion Cubic Feet)**	**Gas Reserves - Net (1) (Billion Cubic Feet)**
Proved Undeveloped	32.694	32.694
Total Proven	32.694	32.694

(1) 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 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

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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, 2006 was $50.70 per barrel based on the Brent spot price per barrel at year end less $7.50 per barrel discount, in line with CanArgo s most recent contractual arrangement. The net gas price used in the Ninotsminda Field report is $0.71 per mcf in line with CanArgo s most recent contractual arrangement. The gas price used in the Kyzyloi and Akkulka Gas Fields report by OPC as of January 1, 2006 ranged from $0.79 per mcf to $1.08 per mcf in line with the Gas Sales Contract for the Kyzyloi Field negotiated with the 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.

No independent reserves have been assessed for the West Rustavi Field. Neither had independent reserves been assessed for the Samgori Field complex. The Company s interest in the Samgori PSC terminated with effect from February 16, 2006.

Undeveloped Acreage

The following table summarizes the gross and net undeveloped acreage held under the Ninotsminda, Nazvrevi/Block XIII, Norio/North Kumisi, Tbilisi and Samgori production sharing contracts as of December 31, 2005. 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, and our 50% interest in the Samgori Block XI^{B} contract through our wholly owned subsidiary CSL. Our interest in the Samgori PSC was terminated with effect from February 16, 2006.

	Gross		**Net**	
PSC	**Acres**	**Square Kilometers**	**Acres**	**Square Kilometers**
Ninotsminda, Manavi and West Rustavi covering Block XI^{E}	27,739	112	27,739	112
Nazvrevi and Block XIII	388,447	1,572	388,447	1,572
Norio (Block XI^{C}) and North Kumisi	381,034	1,542	381,034	1,542
Block XI^{G} and XI^{H} (1)	119,845	485	119,845	485
Samgori and Block XI^{B} (2)	156,664	634	78,332	317
Total	1,073,729	4,345	995,397	4,028

(1) 25% relinquishment March 2006

(2) Exited PSC subsequent to year end, in February 2006

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The following table summarizes the gross and net undeveloped acreage held under the Kazakhstan licenses as of December 31, 2005. The information regarding net acreage represents our interest based on our 70% interest in BN Munai and the subsidiaries holding the licenses through our wholly owned subsidiary TPI.

	Gross		Net	
License	Acres	Square Kilometers	Acres	Square Kilometers
Kyzyloi	70,919	287	49,643	201
Akkulka	411,922	1,667	288,346	1,167
Greater Akkulka	2,751,009	11,133	1,925,706	7,793
Total	3,233,850	13,087	2,263,695	9,161

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 million cubic feet (500,000 cubic meters) per day.

Office Space

We lease office space in London, England; Guernsey, Channel Islands; Tbilisi, Georgia; and Almaty and Aktobe in Kazakhstan. The leases have remaining terms varying from six months to nine years and nine months and annual rental charges ranging from $5,000 to $300,000.

Processing, Sales and Customers Georgia

Georgian Oil built a considerable amount of infrastructure in and adjacent to the Samgori and Ninotsminda Fields prior to entering into the production sharing contracts for these Fields. NOC now use 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. Oil produced from the Samgori Field complex was also transported to Sartichala for treatment prior to sale.

At Sartichala, the water is separated from the oil. NOC and CSL then sell their 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

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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.

NOC sells its oil directly to local and international buyers. In 2005, NOC sold its oil production in accordance with the terms of a sales agreement concluded with Primrose Financial Group (PFG) which included the sale of oil to other customers nominated by PFG under this agreement. During the year, oil was purchased and paid for by a total of 4 customers. Of these customers, the following two customers represented sales greater than 10% of oil revenue:

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

Management believes that the loss of PFG or any of its nominated customers 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.

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%

In 2003, NOC sold its oil production to 11 customers of which the following three customers represented sales greater than 10% of oil revenue:

Customer	**Percent of Oil Revenue**
Crownhill	42.4%
Baslam	32.3%
Sveti	16.9%

For NOC, sales to both the domestic and international markets during 2005 were based on the average of a number of quotations for Dated Brent Mediterranean as quoted in *Platts Crude Oil Marketwire* © with an appropriate discount for transportation and other charges amounting to $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 while the average discounts to the price of Brent crude oil as quoted in *Platts Crude Oil Marketwire* © for Brent Dated Mediterranean for all sales in 2003 was $7.70.

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:

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Year Ended December 31,	Average Sales Price Oil $/boe	Gas $/mcf	Unit Production Cost $/boe
2005	44.78	0.53	14.83
2004	24.94	1.41	5.81
2003	20.07	1.25	2.59

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 CSL, sales to both the domestic and international markets during the twelve month period to end-December 2005 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 2005 was $6.16 per barrel. The discount during the nine months of trading in 2004 was $5.12 per barrel. The higher discount during 2005 is 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 in 2005 and 2004 was as follows:

Year Ended December 31,	Average Sales Price Oil $/boe	Gas $/mcf	Unit Production Cost $/boe
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;

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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 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.

On March 3, 2006, we announced that CNZ had signed a Memorandum of Understanding (MOU) which includes the terms of a take-or-pay natural gas supply contract with the Ministry of Energy of Georgia relating to gas sales from the Kumisi gas prospect. The MOU will become effective subject to final regulatory approval. The MOU provides the commercial basis for CNZ to move forward with the appraisal of Kumisi and, based on this, CNZ plans to spud a well on Kumisi between May and December 2006. The MOU contains the terms of a take-or-pay gas supply contract 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 US$ 1.56 per thousand cubic feet, increasing to US$ 2.28 per thousand cubic feet by the tenth contract year, after which escalation will be based on European Union heavy fuel oil price changes. The gas supply contract is 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 Kumisi prospect is located approximately 9 miles (15 Km) south of Tbilisi. The WR16 well, drilled in Soviet times, is reported to have tested gas condensate from what is interpreted as the gas-water contact in the Cretaceous/Palaeocene horizon. This well was tested and produced gas plus water at a rate of approximately 3,500 barrels per day and is interpreted to have tested the down-dip extent of the Kumisi gas deposit. Additional seismic data acquired by CNZ over this structure shows a significant up-dip prospect and the location for the Kumisi #1 well has been identified. The prospect is potentially of very significant size with the principal risk being closure on the structure.

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 262,919 acres (1,064 Km ^{2}), following the first contractual relinquishment, 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 25% of the original contract area, but not any portions being actively developed, by the fifth anniversary of the effective date (which has been done) and then 50% of the remaining area 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 under a service agreement with CNL, 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.

The second phase of the preliminary work program under the Norio PSA commenced in January 2002 with the first exploration well named MK72 drilled on a large prospect identified at Middle Eocene level which is analogous to the nearby Samgori Field immediately to the south of the block. It has been reported that the Samgori Oil Field has produced approximately 180 million barrels of oil to date.

The MK72 well was initially drilled to a depth of 9,620 feet (2,932 meters), at which depth the well was suspended in August 2002 due to lack of available funding at that time. Although, the primary target of the Middle Eocene had not been encountered, the State Agency for the Regulation of Oil and Gas Resources in Georgia confirmed that CNL had satisfied all drilling and work obligations under the terms of the Norio PSA by the initial phase of drilling of the MK72 well.

In connection with this initial phase of drilling, which cost a total of $4.3 million, our partner in CNL sought to farm-out to us and to third party investors part of its interest in CNL to partly fund the drilling of the MK72 well. One of these third party investors was Provincial Securities Limited, an investment company to which Mr. Russell Hammond, a non-executive director of CanArgo, is an Investment Advisor. CNL s total share of these drilling costs was $3.1 million. In November 2002, shareholders of CNL agreed to adjust the ownership of CNL to reflect the funding for the MK72 well, and capitalization of certain loans and management fees that we had made to CNL. Under this agreement, our interest increased from 50% to 64.2% in CNL. CNL then sought a partner to assist with the financing to deepen the MK72 well.

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. CNL had previously been in negotiations with a large third party energy company to farm-in to the Norio PSA, but Georgian Oil exercised its pre-emption rights under the Norio PSA. Georgian Oil is already a party to the Norio PSA as the commercial representative of the State. The 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 (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 $ 6.5 million

Co-incident with the Georgian Oil farm-in, we concluded a deal 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, thus increasing our interest to 75%. The purchase was achieved by issuing 6 million restricted CanArgo common shares to the minority interest holders in CNL. Of the interests in CNL, Provincial Securities Limited owned 4%. On September 30, 2004 we acquired the remaining minority shareholders who held a 25% interest in CNL. We issued a further 6 million restricted common shares in connection with this transaction.

In accordance with the terms of the farm-in agreement, Georgian Oil invested $1,758,000 in deepening the MK72 well. Drilling recommenced in December 2003 and the well was drilled ahead to a depth of 14,830 feet (4,520 meters). The well was cased, having encountered oil bearing sands in the Oligocene formation which is a secondary objective for the well. Electric logs run over the Oligocene sequence indicate over 330 feet (100 meters) of net pay sands with porosities in the range of 8 to 28%, with an average of 13%. From the oil shows while drilling and log analysis, these sands appear to be oil bearing. It was planned to test the Oligocene sands once the well has reached total depth. Data obtained from a vertical seismic profile run in the well at this depth indicated that there was a seismic reflector at 15,744 feet (4,800 meters) which could be the Middle Eocene objective. Due to Georgian Oil s inability to continue to fund the drilling of the well, operations were subsequently suspended.

On May 9, 2005 we announced that CNL had signed final documentation with Georgian Oil for CNL to secure 100% of the contractor share in the Norio PSA. On May 20, 2005 we paid Georgian Oil $1,758,000 to terminate the Agreement and Option and secure a 100% working interest in the Norio PSA.

In late June, we recommenced drilling operations on the suspended MK72 well and on August 26, 2005 we announced that the Saipem Ideco E-2100Az drilling rig and Baker-Hughes oil-based mud system was being mobilized to the MK72 Norio exploration well. Our Ural Mash Rig had difficulty drilling through a highly over-pressured section of swelling clays above the prognosed target zone and as the Saipem Rig with its oil-based mud system had successfully drilled through a similar section in the M11Z well, it was considered that this afforded the best option to completing the well. MK72 was sidetracked and successfully drilled through the over-pressured section encountering the top of the Middle Eocene primary target zone at 15,787 feet (4,812 meters). A 5 inch (127 millimetre) liner was run to 15,899 feet (4,846 meters) before drilling ahead through the reservoir using slim hole technology.

On December 29, 2005 we announced that the MK72 well reached a depth of 4,900 meters (16,076 feet) in the Middle Eocene reservoir having encountered very good oil and gas shows. Gas levels up to 21% were recorded at surface, as well as light oil in the mud and hydrocarbon fluorescence in the cuttings samples. Inflow was observed and it appeared that the small diameter hole collapsed around the bit. Although it may have been possible to mill down the BHA and to sidetrack the hole, the small hole diameter and unstable hole conditions meant that there was a high risk that such an operation would not be successful and could take an indeterminate time. As such it was decided to plug back the lower part of the hole and to concentrate on testing the oil-bearing 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.

The lower section of the well has now been plugged back and the Saipem rig has been moved to the M12 appraisal location while the CanArgo rig #2 has been mobilised to the MK72 well location in preparation for the testing of the Oligocene sand interval. High penetration tubing conveyed and through tubing perforating guns have been imported from the United States for the test program. Ten separate zones of interest between 12,057 feet (3,675 meters) MD and 13,337 feet (4,065 meters) MD have been selected for testing. The lowermost zone, a 10 feet (3 meter) interval below the primary test zones has now been perforated, primarily to give formation pressure data for the main tests which are expected to commence shortly. Given significant production is tested, the well would be placed on long term test production.

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 have 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 and the structure which is being tested. Both the Oligocene and Middle Eocene prospects as mapped are potentially large and lie just to the north west of Georgia s largest oil field, the Samgori Field which is reported to have produced over 180 million barrels of oil to date. Following a successful test of the Oligocene interval, it would be intended to commence an appraisal drilling program later this year or early next year operations permitting. It is also planned that an appraisal well will be drilled to fully evaluate the Middle Eocene discovery sometime next year, 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. CNL will evaluate existing seismic and geological data during the first year and acquire additional seismic data within three years of the effective date of the PSC which was set as 29 September 2003. The total commitment over the next seven months 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 extends into the southern part of Block XI^G, and this prospect will be evaluated by the well which is planned to be drilled on the prospect within the Nazvrevi PSC just to the south of the block boundary with the Tbilisi PSC in the latter half of 2006.

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 (TPI) 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 contract and Kyzyloi production contract. Immediately prior to the agreement between TPI and ACR, and as part of that transaction, we entered into an agreement allocating a 45% 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, help and assistance concerning funding the development of TPI. This transaction resulted in us holding a 45% non-controlling interest in TPI with the remaining interest holder in TPI 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.

TPI 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 TPI 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 TPI by way of a share exchange with the other owners of TPI and TPI 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 TPI 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 TPI.

BNM s interest centers on the Akkulka area, a 411,922 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 70,919 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 is involved in an extensive workover and testing program of wells on the field, with the last well in the program, KYZ109 now in the process of being tested. 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 33 mile (53 Km) pipeline will be constructed to connect the Kyzyloi development to the Bukhara-Urals gas trunkline, with the initial planned production rate being 17.7 million cubic feet (500,000 cubic meters) per day and with first gas planned for late summer 2006. 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. BNM is currently funded through loan agreements with TPI s wholly owned subsidiary, Tethys Kazakhstan Limited.

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 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 thousand cubic feet ($32 per thousand cubic meters) 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.

A five well exploration program targeting shallow gas anomalies which may be similar to the Kyzyloi Field is underway within the Akkulka Licence area with two new discoveries having already been made. 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 million cubic feet (250,000 cubic meters) of gas per day, and AKK05 (now named North-East Kyzyloi), located 4 miles (6.5 Km) north east of the Kyzyloi Field, flowed gas at a rate of 8.2 million cubic feet (233,000 cubic meters) per day. It is planned to apply for an extension to the Kyzyloi Field Production Contract to include the AKK05 discovery, and 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 AKK04 discovery has been fully evaluated.

In the other two exploration wells which have been drilled to date, AKK02 and AKK03, gas indications have been observed during drilling and in thin sands on wireline logs. These wells lie to the south east of the Kyzyloi Field, and may have encountered another gas deposit. It is planned to test these wells as part of an integrated testing program, but operations have been hampered by weather conditions. The next exploration well, AKK01 should commence once a rig is available from the Kyzyloi development program.

Initial work is now completed on a geophysical remapping of the Akkulka exploration block. This work has confirmed the presence of several 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 23, 2005 we announced that BNM had completed the acquisition of a 100% interest in the Greater Akulka Exploration 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 2.75 million acres (11,133 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.

Refining and Other Activities

We also have engaged in other oil and gas activities in Georgia and elsewhere. Discontinued Operation activity is incorporated herein by reference from note 20 to the consolidated financial statements.

Georgian American Oil Refinery

As the Georgian American Oil Refinery (GAOR) remained in a care and maintenance condition during 2003 with little prospect of the plant being returned to a commercially viable operation, we came to an agreement to sell the refinery and we disposed of our 51% interest in GAOR in February 2004. 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 our plan to dispose of the asset.

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.

Caspian Exploration Project

In May 1998, CanArgo led a consortium which submitted a bid in a tender for two large exploration blocks in the Caspian Sea, located off the shore of the autonomous Russian Republic of Dagestan. The consortium was the successful bidder in the tender and was awarded the right to negotiate licenses for the blocks. Following negotiations, licenses were issued in February 1999 to a majority-owned subsidiary of CanArgo. During 1999 we concluded that we did not have the resources to advance this project. Accordingly, in November 1999, we reduced our interest to 9.5%. Subsequent to this, a restructuring of interests in the project took place with us increasing our interest slightly to 10%, and with Rosneft, the Russian state owned oil company, becoming the majority owner of the project with 75.1%. Seismic was acquired as part of this restructuring and future plans include interpretation of this data and possible drilling. However, due to our small interest in this project and our inability to secure an effective joint operating agreement, we have had little or no control over the operator. As management does not contemplate any further investment in this project, we fully impaired our $75,000 investment in the Caspian exploration project during the year ended December 31, 2004.

Discontinued Operations

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 in originally 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. Discontinued Operation activity is incorporated herein by reference from note 20 to the consolidated financial statements.

GAOR

In 2003, we approved a plan to dispose of our interest in 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 reach agreement with a local Georgian company to sell our 51% interest in GAOR for a nominal price of one US dollar and the assumption of all the obligations and debts of GAOR to the State of Georgia including deferred tax liabilities of approximately $380,000. In 2003, we announced publicly that we were re-evaluating our treatment in our 2001 and 2002 financial statements of our minority interest in GAOR. After reviewing the basis for our accounting for our interest in GAOR and after discussions with our former auditors we have concluded that our interest was properly accounted for in those statements.

Bugruvativske Field, Ukraine

Lateral Vector Resources Inc. (LVR), a wholly-owned indirect subsidiary of CanArgo acquired by us in July 2001, negotiated and concluded with Ukrnafta, the Ukrainian State Oil Company, a Joint Investment Production Activity (JIPA) agreement in 1998 to develop the Bugruvativske Field located in Eastern Ukraine.

In 2003, due to the lack of progress with the implementation of the JIPA, and failure to reach a negotiated agreement with Ukrnafta, management reached the decision to dispose of its interest in the Bugruvativske project and withdraw from Ukraine. Consequently, we recorded in 2003 a write-down in respect to the LVR deal and the acquisition of the Bugruvativske Field of approximately $4,790,727.

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 through the disposal of LVR 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 March 14, 2006, we had not received any further payments.

We have now effectively withdrawn from Ukraine, in order to focus principally on our Georgian activities, having disposed previously of our interest in the Stynawske Field in Western Ukraine in 2003. Our interest in the Stynawske Field was sold for $1,000,000 and the buyer has also acknowledged debts of the joint venture company which operates the field to us for earlier loans in the total amount of $160,000.

3-megawatt duel fuel power generator

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.

Employees

As of December 31, 2005, we had 189 full time employees. Of our full time employees, the entity acting as operator of the Ninotsminda Field for Ninotsminda Oil Company has 143 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 currently employs 29 full time employees in Almaty and Aktobe principally involved with work on the Kyzyloi Field development. 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 intends to file 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

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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 thus bringing the relief sought pursuant to both claims to the sum of 32.4 million GEL (approximately $19.0 million at the exchange rate of GEL to US dollars in effect on December 31, 2005). At a hearing in March 2006 the defendants increased the amount of damages sought to 50,000 GEL (approximately $29,000) per defendant, which increased the total claim to approximately $182,000,000.

We believe that we have meritorious defenses to both claims and intend to defend them vigorously.

The Company has been named in a legal action commenced in Alberta, Canada, with a group of defendants by former interest holders of the Lelyakov oil field in the Ukraine. The defendants are seeking damages of approx 600,000 CDN (approx $514,000 at December 31 exchange rates). The former owners of UK-Ran Oil Corporation 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.

Other than the foregoing, as at December 31, 2005 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, 2005.

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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 high and low bid prices on the OTCBB and AMEX for the periods indicated. Average daily trading volume on these markets during these periods is also provided. OTCBB data is provided by the NASDAQ Trading and Market Services and/or published financial sources and OSE and AMEX data is derived from published financial sources. The over-the-counter quotations reflect inter-dealer prices, without retail mark-up, markdown or commissions, and may not represent actual transactions. 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.

	OTCBB			OSE			AMEX		
	High	Low	Average Daily Volume	High	Low	Average Daily Volume	High	Low	Average Daily Volume
Fiscal Quarter Ended									
March 31, 2004	1.22	0.48	719,195	1.22	0.44	6,378,789			
June 30, 2004*				1.04	0.66	2,234,149	1.08	0.60	243,473
September 30, 2004				0.71	0.43	1,260,468	0.74	0.47	308,636
December 31, 2004				1.23	0.69	2,929,357	1.32	0.67	1,120,177
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

* The Common Stock ceased trading on the OTCBB and began trading on the AMEX on April 21, 2004. The amounts reflected for the June 30, 2004 fiscal quarter include the

trading results on both the OTCBB and the AMEX for the entire quarterly period.

At March 10, 2006, the closing price of our common stock on the AMEX and the OSE was $ 1.12 and $ 1.06, respectively. On March 10, 2006 one U.S. dollar equalled 6.73 Norwegian kroner.

On March 10, 2006 the number of holders of record of our common stock was approximately 14,000. We have not paid any cash dividends on our common stock. 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.

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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.

The following data 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.

Reported in $000 s except for per common share amounts			**Year Ended December 31,**		
	2005	**2004**	**2003**	**2002**	**2001**
Financial Performance					
Operating revenues from continuing operations	7,582	9,574	8,105	5,486	4,575
Operating loss from continuing operations	(11,009)	(2,954)	(159)	(4,902)	(11,838)
Other income (expense) and Minority Interest in income (loss) of consolidated subsidiaries	(1,327)	(2,346)	(597)	(576)	525
Net loss from continuing operations	(12,335)	(5,300)	(756)	(5,478)	(11.313)
Net income (loss) from discontinued operations, net of taxes and minority interest (1)		542	(6,608)	150	(1,905)
Cumulative effect of change in accounting policy			41		
Net loss	(12,335)	(4,758)	(7,323)	(5,328)	(13,218)
Net loss per common share basic and diluted before cumulative effect of change in accounting principle from continuing operations	(0.06)	(0.04)	(0.01)	(0.06)	(0.14)
Net loss per common share basic and diluted before cumulative effect of change in accounting principle from discontinued operations	(0.06)	(0.04)	(0.07)	(0.00)	(0.02)
Net loss per common share basic and diluted	(0.06)	(0.04)	(0.08)	(0.06)	(0.16)
Cash generated by (used in) operations	(4,651)	(3,781)	4,431	1,635	(6,289)
Working capital	15,078	23,952	3,890	10,646	14,590
Total assets	147,448	105,160	73,360	70,736	70,312

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Reported in $000 s except for per common share amounts			**Year Ended December 31,**		
	2005	**2004**	**2003**	**2002**	**2001**
Minority shareholder advances				-- 4	50
Stockholders equity	107,849	96,821	56,708 62,	105	65,800
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 Caurtionary 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 1.A 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 5.499 MMbbl down 12% from 2004 s 6.271 MMbbl. Over the same period, gross total proved natural gas reserves increased from 2.620 billion cubic feet to 35.196 billion cubic feet, primarily with the addition of the Kyzyloi Field in Kazakhstan.

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

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 wellbores on our Ninotsminda and Samgori Fields. 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 including: N22H: N30H: a second horizontal well, N100H2 east horizontal, from the N100 well bore (which achieved good rates of production when drilled horizontally with conventional techniques and which was later the subject of a blow out in September 2004); N49H: N97H, and a new well (N99) designed so as to have more than one horizontal wells drilled from it. The N99 well was planned for the eastern part of the Field, an area that is currently largely undeveloped.

UBCTD operations started on the first well in the program, the N22H well, in December 2004. The well is located in the east part of the Ninotsminda 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 under balanced drilling 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 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. In this respect, we continue to investigate the potential of bringing an alternative supplier of such equipment and services to Georgia.

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. On October 27, 2005 we reached total depth (TD) on the first sidetrack, the N100H2 well. The well was completed in the Middle Eocene reservoir at approximately 8,659 feet (2,640 meters) TVD (True Vertical Depth) 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 million cubic feet

(370,000 cubic meters) 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 horizontal section is located in the uppermost part of the oil zone, close to the gas-oil contact, and a permeable interval was encountered in the build up section within the lower part of the gas cap. It is expected that the proportion of liquid hydrocarbon production will rise over time. The well is currently choked back as we await completion of repairs by the state oil company, Georgian Oil, to the 22.4 mile (36 Km) pipeline which it is planned will deliver the gas from Ninotsminda to the local State-run thermal electricity generating station at Gardabani. Terms have been agreed with the government for a gas supply agreement from the Ninotsminda Field and it is expected that an agreement will be signed in the near future.

In November 2005, we announced that operations had commenced on the next horizontal sidetrack well on the Ninotsminda Field, N97H. This sidetrack was more complicated than the N100H2 well as it is located on the northern flank of the field and it was be necessary to first sidetrack the well from a much shallower level towards the crest of the field before the horizontal section could be drilled through the reservoir in a westerly direction along the crest of the structure. The well was drilled by us using our own rig and equipment while utilising directional equipment and services provided by Baker Hughes. In February 2006 we announced that drilling been completed with a 1,725 feet (534 meter) horizontal section having been drilled through the Middle Eocene reservoir and a 1,490 feet (454 meter) slotted production liner run. The wall is currently being tested.

In 2006, on completion of the N97H sidetrack, we plan to drill two further horizontal sidetrack wells from the N49 and N46 wells. We have budgeted approximately $6 million for such development work on the nInotsminda Field in 2006.

Kyzyloi

On the Kyzyloi Gas Field a development program is underway. BNM is involved in an extensive workover and testing program of wells on the field, with the last well in the program, KYZ109 now in the process of being tested. 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 33 mile (53 Km) pipeline will be constructed to connect the Kyzyloi development to the Bukhara-Urals gas trunkline, with the initial planned production rate being 17.7 million cubic feet (500,000 cubic meters) per day and with first gas planned for late summer 2006. 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.

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 $10.8 million in the Kyzyloi development in 2006.

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 .

[1] using 6,000 cubic feet of gas = 1 barrel of oil/condensate

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Exploration and Appraisal

Manavi

Attempts to recover the damaged tubing from the M11 original oil discovery well on the Manavi structure were unsuccessful and in late 2004 we commenced a sidetrack to this well. Despite an upgrade to our drilling equipment which included more powerful mud pumps and bicentrical drilling bits we continued to encounter drilling problems due to the extremely over-pressured swelling clays above the reservoir intervals. After extensive technical analysis and discussions with the international drilling contractor Saipem S.p.A. (Saipem), and Baker-Hughes International, a major drilling mud company, it was decided that the optimum way to sidetrack this well to the top of the reservoir as planned was to use an oil-based mud system (to control the swelling clays) on the Sapiem Ideco E-2100Az drilling rig (which is equipped with a top-drive drilling system and can use an oil-based mud system unlike our current Ural-Mash rig). Service contracts were subsequently concluded with Saipem to provide a rig and drilling services to the company and with Baker-Hughes for the provision of an oil-based mud system.

On August 26, 2005 we announced that the Manavi M11Z well had reached a total depth (TD) of 14,994 feet (4,570 meters) measured depth (MD) in the Cretaceous. 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) MD some 230 feet (70 meters) MD higher than in the original M11 well while the secondary Middle Eocene target zone was penetrated at 13,009 feet (3,965 meters) MD again significantly higher than in the M11 well. Drilling data and slim hole wireline logs indicate the presence of hydrocarbons in both the Cretaceous and Middle Eocene target zones.

On October 6, 2005 we announced that we had commenced testing operations on M11Z. A pre-perforated $2^{7/8}$ inch (73mm) liner was run in the slim hole, and the Saipem drilling rig removed from the site while CanArgo Rig #1 was mobilized to the location for testing operations. During initial testing operations it emerged that the section of the liner adjacent to the cretaceous limestone interval had 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 wellbore 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-wellbore damage is through the application of acid using coiled tubing, and if necessary perforate. Currently it is planned to carry out an acid stimulation and complete the well test using a Schlumberger supplied coiled-tubing unit, pumping equipment and completion fluids. The delay in testing this well has been due to the difficulty in sourcing a coil tubing unit to Georgia. It is expected that testing will re-commence in the M11Z well during April 2006.

We have identified further appraisal locations on the Manavi structure. Drilling operations at the first appraisal site, M12 using the Saipem rig commenced on February 9, 2006. 20 inch (508 mm) casing has now been set and the well is currently operating in 17 ½ inch (445 mm) hole section. The well is located approximately 2.5 miles (4 Km) to the west of the M11 discovery well. CanArgo rig #2 was used to spud the well and drill the surface casing section to a depth 1,302 feet (397 meters) whilst Saipem completed operations on the MK72 well. M12 has a planned total depth of 15,092 feet (4,600 meters), and is expected to be completed in the summer of 2006.

Given significant production is tested from either the M11Z or the M12 wells, these wells would be placed on long term test production which would involve putting in place an early production facility.

Norio

On May 9, 2005 we announced that our subsidiary CNL had signed final documentation with Georgian Oil for CNL to secure 100% of the contractor share in the Norio PSA. On May 20, 2005 we paid Georgian Oil $1,758,000 to terminate their farm in agreement to the PSA and secured a 100% working interest in the Norio PSA and so enabled us to move forward with the completion of the MK72 exploration well. Operations had been suspended in 2004 when Georgian Oil were not able to finance the drilling of the well under their September 2003 farm in obligations.

In late June 2005, we recommenced drilling operations on the suspended MK72 well and on August 26 we announced that the Saipem Ideco E-2100Az drilling rig and Baker-Hughes oil-based mud system was being mobilized to the MK72 Norio exploration well. Our Ural Mash Rig had difficulty drilling through a highly over-pressured section of swelling clays above the prognosed target zone and as the Saipem Rig with its oil-based mud system had successfully drilled through a similar section in the M11Z well, it was considered that this afforded the best option to completing the well. MK72 was sidetracked and successfully drilled through the over-pressured section encountering the top of the Middle Eocene primary target zone at 15,787 feet (4,812 meters). A 5 inch (127 millimetre) liner was run to 15,899 feet (4,846 meters) before drilling ahead through the reservoir using slim hole technology.

On December 29, 2005 we announced that the MK72 well reached a depth of 4,900 meters (16,076 feet) in the Middle Eocene reservoir having encountered very good oil and gas shows. Gas levels up to 21% were recorded at surface, as well as light oil in the mud and hydrocarbon fluorescence in the cuttings samples. Inflow was observed and it appeared that the small diameter hole collapsed around the bit. Although it may have been possible to mill down the BHA and to sidetrack the hole, the small hole diameter and unstable hole conditions meant that there was a high risk that such an operation would not be successful and could take an indeterminate time. As such it was decided to plug back the lower part of the hole and to concentrate on testing the oil-bearing 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.

The lower section of the well has now been plugged back and the Saipem rig has been moved to the M11 appraisal location while the CanArgo rig #2 has been mobilised to the MK72 well location in preparation for the testing of the Oligocene sand interval. High penetration tubing conveyed and through tubing perforating guns have been imported from the United States for the test program. Ten separate zones of interest between 12,057 feet (3,675 meters) MD and 13,337 feet (4,065 meters) MD have been selected for testing. The lowermost zone, a 10 feet (3 meter) interval below the primary test zones has now been perforated, primarily to give formation pressure data for the main tests which are expected to commence shortly. Given significant production is tested, the well would be placed on long term test production.

In 2006, we have budgeted approximately $12.5 million for our exploration and appraisal work in Georgia, primarily for the appraisal of the Manavi discovery.

<u>Akkulka</u>

A five well exploration program targeting shallow gas anomalies which may be similar to the Kyzyloi Field is underway within the Akkulka Licence area with two new discoveries having already been made. 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 million cubic feet (250,000 cubic meters) of gas per day, and AKK05 (now named North-East Kyzyloi), located 4 miles (6.5 Km) north east of the Kyzyloi Field, flowed gas at a rate of 8.2 million cubic feet (233,000 cubic meters) per day. It is planned to apply for an extension to the Kyzyloi Field Production Contract to include the AKK05 discovery, and 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 AKK04 discovery has been fully evaluated.

In the other two exploration wells which have been drilled to date, AKK02 and AKK03, gas indications have been observed during drilling and in thin sands on wireline logs. These wells lie to the south east of the Kyzyloi Field, and may have encountered another gas deposit. It is planned to test these wells as part of an integrated testing program in the near future but operations have been hampered by weather conditions. The next exploration well, AKK01 should commence once a rig is available from the Kyzyloi development program.

Initial work is now completed on a geophysical remapping of the Akkulka exploration block. This work has confirmed the presence of several 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.

We have budgeted $3.3 million for exploration work in Kazakhstan in 2006, primarily for exploration drilling on shallow gas targets in the later part of the year.

While a considerable amount of infrastructure for the Ninotsminda 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 Fields will be timely;
- that the development plan will be successfully completed or will increase production; or
- that operating revenues from the Fields after completion of the development plan will exceed operating costs.

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,

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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.

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 March 10, 2006, the Company had an aggregate of 224,108,606 shares of common stock issued and outstanding and 300,000,000 authorized shares of common stock. During 2005, we issued 27,374,778 shares of which 13,012,945 shares were in connection with the Standby Equity Distribution agreement with Cornell Capital, 11,000,000 shares were in connection with the Tethys acquisition, 3,281,833 shares were in connection with exercise of stock options and 80,000 were in connection with a consultancy agreement related to investor relations services. During 2006, we have issued 1,521,739 shares of our common stock in connection with the conversion of a Convertible Loan. As of March 14, 2006, an aggregate of 62,844,598 shares are reserved for issuance under various stock option plans, warrants and other contractual commitments, including the Senior Secured Notes and the Subordinated Notes.

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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, 2005, we had working capital of $15,078,000, compared to working capital of $23,952,000 as of December 31, 2004. The $8,874,000 decrease in working capital from December 31, 2004 to December 31, 2005 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, further drilling of the Norio exploration well, activities in Kazakhstan and net cash used by operating activities partially offset by cash received pursuant to the takedowns under the SEDA and the Senior Secured Notes.

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) (Sales Agreement). 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 replaces 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 has a minimum term of 45 months and contains the following principal terms:

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(i) NOC will make available to PFG NOC s entire share of production from the Ninotsminda Field including a minimum total amount of 68,555 metric tonnes (the Minimum Contract Quantity). In the event NOC fails to produce the Minimum Contract Quantity it will have no liability to PFG;

(ii) The delivery point shall be at Georgian Oil s storage reservoirs at Samgori (adjacent to the Ninotsminda Field);

(iii) The price for the oil will be in US Dollars per net US Barrel equal to the average of the mean of three quotations in *Platts Crude Oil Marketwire*© for Brent Dated Quotations minus a discount: ranging for sales (a) up to the Minimum Contract Quantity from $6.00 to $7.50 based on Brent prices per barrel ranging from less than $15.00 to greater than $25.01, respectively; and (b) for sales of oil in excess of the Minimum Contract Quantity at the commercial discount in Georgia for oil of similar quality less $0.10 per barrel with the maximum discount being $6.00 per barrel for export sales and $5.50 per barrel for local sales; and

(iv) PFG will pay NOC for the monthly quantity of oil in advance of delivery.

NOC s obligations are subject to customary Force Majeure provisions, title and risk of loss pass to buyer at the delivery point, NOC agrees to assist the buyer to sell the oil locally or export oil in accordance with applicable law and the Agreement is governed by English law.

Certain Asset Sales

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.

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.

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 will 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 placement agent 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 May 19, 2004, we signed a promissory note with Cornell Capital whereby they agreed to advance us the sum of $1,500,000. This amount was payable on the earlier of 180 days from the date of the promissory note or within 60 days from the date that the Registration Statement on Form S-3 was declared effective. If the promissory note was not repaid in full when due, interest accrued on the outstanding principal owing at the rate of twelve per cent (12%) per annum. At Cornell Capital s option any such interest due was to originally be paid either in shares of our common stock or in cash. However, on December 21, 2004 we entered into a letter of amendment with Cornell Capital which provided that any sums due in respect of interest accrued on the promissory note would be paid in cash only. We paid Cornell Capital a commitment fee of five per cent (5%) of the principal amount of the promissory note which was set off against the first $75,000 of fees payable by us to Cornell Capital under the Cornell Facility. The promissory note was to become immediately due and payable upon the occurrence of any of the following: (i) failure to pay the amount of any principal or interest when due under the promissory note or (ii) if any proceedings under any bankruptcy laws of the United States of America or under any insolvency, reorganisation, receivership, readjustment of debt, dissolution, liquidation or any similar law or statute of any jurisdiction are filed by or against us for all or any part of our property. The proceeds of advances from Cornell Capital was used by us to order long lead items for our drilling program in Georgia and for working capital purposes.

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 $1.67 per share under the Cornell Facility. This provided net proceeds of $600,000 to CanArgo.

As at March 14, 2005 we had received $2,102,048 pursuant to 4 takedowns under the Cornell Facility in which we issued a total of 1,431,846 shares of our common stock to Cornell Capital.

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 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 estimated at $550,000, have 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 our projects in Georgia and to a lesser extent in Kazakhstan. In addition, we terminated the SEDA which we had with Cornell Capital with effect as of August 24, 2005.

In connection with the placement of the Senior Secured Notes we entered into a Note Purchase Agreement with a group of private investors (the Purchasers), all of whom represented that they qualified as accredited investors under Rule 501(a) promulgated under the Securities Act. Pursuant to the Note Purchase Agreement, we issued a note due July 25, 2009 in the aggregate principal amount of $25,000,000 to Ingalls & Snyder LLC, as nominee for the 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 is deemed a beneficial holder of the Note and such Purchasers may each be assigned their own Note as provided in the Note Purchase Agreement and, accordingly, all such Notes are referred to herein collectively as the Note and any such Purchaser or its assignee is referred to herein as a holder of the Note.

On March 3, 2006, we announced that we had entered into a $13,000,000 private placement with a small group of accredited investors (Noteholders) of Senior Subordinated Convertible Guaranteed Notes due September 1, 2009 (the Subordinated Notes) and two year warrants to purchase an aggregate of 13,000,000 shares of common stock (Warrants).

The Subordinated Notes are convertible in whole or in part into CanArgo common stock at a price of $1.37 per share, subject to certain anti-dilution adjustments, and will mature on September 1, 2009. Subject to the consent of the Senior Secured Note holders, CanArgo may call the Subordinated Notes from March 1, 2007 at an initial price of 105% of par, declining 1% every six months. Interest will be payable in cash at 3% per annum until December 31, 2006, 10% per annum thereafter. The Subordinated Notes are subordinated to CanArgo s existing issue of Senior Secured Notes and guaranteed on a subordinated basis by CanArgo s material subsidiaries.

The Warrants are exercisable in whole or in part for CanArgo common stock at an exercise price of $1.37 per share, subject to adjustment. The expiration date of the Warrants may be accelerated at CanArgo s option in the event that the Manavi M12 appraisal well in Georgia (which is currently being drilled) indicates, by way of an independent engineering report, sustainable production potential, if developed, in excess of 7,500 barrels of oil per day.

The proceeds are to be used to fund the development of the Kyzyloi Gas Field in Kazakhstan and on the commitment exploration programs in Kazakhstan through Tethys Petroleum Investments Limited (Tethys), the wholly owned subsidiary of CanArgo which holds CanArgo s Kazakhstan assets.

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The Subordinated Note holders will have the right (as an alternative) until March 3, 2007 (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 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 in the Subordinated Note holders Relevant Percentages (as defined in the Note Purchase Agreement). At the time of any Tethys conversion any further advances (in excess of the $13 million) from CanArgo to Tethys may be, at CanArgo s discretion, either repaid, or converted into Tethys equity based on a valuation of $52 million with the Subordinated Note holders having the ability to maintain their equity position by providing further funding on a pro-rata basis.

Predicted cash flows from our Georgian operations together with the proceeds of the private placement of a $25,000,000 issue of Senior Secured Notes (detailed above) and proceeds of the private placement of a $13,000,000 issue of Subordinated Notes (detailed above) means we believe that we have the working capital necessary to cover our immediate and near term funding requirements with respect to our currently planned development activities in Georgia on our Ninotsminda Field and the currently drilling Manaui appraisal well, and our initial development plans in the Kazakhstan, absent any unforeseen circumstances including lower than expected production levels or overuns.

Working Capital

At December 31, 2005, our current assets of approximately $28.2 million exceeded our current liabilities of $13.1 million resulting in a working capital surplus of approximately $15.1 million. This compares to a working capital surplus of $24.0 million as of December 31, 2004. Current liabilities as of December 31, 2005 consisted of (in the following approximate amounts) trade payables of $5.7 million, $1.0 million promissory note, and accrued liabilities of $6.4 million.

Capital Expenditures

Capital expenditures in cash in 2005, 2004 and 2003 were $33.5 million, $11.2 million and $5.3 million, respectively. The table below sets forth the components of these capital expenditures for the three years ended December 31, 2005 2004 and 2003.

		December 31,	
Expenditure category:	**2005**	**2004**	**2003**
Development	$13,839,580	$ 6,588,137	$5,200,614
Exploration	15,316,075	1,757,010	(328,998)
Facilities and other	4,294,928	2,845,143	411,772
Total	33,450,583	11,190,290	5,283,388

The negative expenditures recorded in Exploration in 2003 is a result of a prior year reclassification.

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During 2005, 2004 and 2003 capital expenditures were primarily for the development and exploration of existing properties. We currently have a contingent planned minimum capital expenditure budget of $33 million subject to financing being available for 2006, of which $20 million is allocated to our Georgian development and appraisal projects and $13 million is allocated to our Kazakhstan projects. During 2006, we plan to participate in the drilling of up to three horizontal wellbores on the Ninotsminda Field, complete the testing of the Manavi appraisal well, M11Z, drill one appraisal well on the Manavi structure, and test the Oligocene oil discovery in the Norio MK72 exploration 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.

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,	
	2005	**2004**	**2003**
Net cash generated (used in) operating activities	$ **(8,268,790)**	$ (3,781,078)	$ 4,430,922
Net cash used in investing activities	**(33,696,496)**	(9,967,084)	(3,228,768)
Net cash provided in financing	**35,888,797**	34,771,028	875,325
Net cash flows from assets and liabilities held for sale		121,929	(190,227)
Total	**(6,076,489)**	21,144,795	1,887,252

Operat