CANARGO ENERGY CORP
Form 10-K
March 16, 2005

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

FOR ANNUAL AND TRANSITION REPORTS
PURSUANT TO SECTIONS 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

þ **ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE FISCAL YEAR ENDED DECEMBER 31, 2004**

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 0-9147

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 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 herein by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

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, 197,766,338 shares outstanding as of 14 March, 2005.

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act).
YES þ NO o

The aggregate market value of the Registrant s common stock held by non-affiliates was approximately $334.6 million as of 11 March 2005, 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.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant s definitive Proxy Statement to be issued in connection with its 2005 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

Qualifying Statement With Respect To Forward-Looking Information

The United States Private Securities Litigation Reform Act of 1995 provides a safe harbour for certain forward-looking statements. Such forward-looking statements are based upon the current expectations of CanArgo Energy Corporation (CanArgo or the Company) and speak only as of the date made. These forward-looking statements involve risks, uncertainties and other factors. The factors discussed in Item 1. Business Risks Associated with CanArgo s Oil and Gas Activities , Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and elsewhere in this Annual Report on Form 10-K are among those factors that in some cases have affected CanArgo s historic results and could cause actual results in the future to differ significantly from the results anticipated in forward-looking statements made in this Annual Report on Form 10-K, future filings by CanArgo with the Securities and Exchange Commission, in CanArgo s press releases and in oral statements made by authorized officers of CanArgo. When used in this Annual Report on Form 10-K, the words estimate, project, anticipate, expect, intend, believe, hope, may and similar expressions, as well as will, shall and other in future tense, are intended to identify forward-looking statements.

In this Annual Report, CanArgo or the company , we , us and our refer to CanArgo Energy Corporation and, unle 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.

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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.

mD A milli Darcies.

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.

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.

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 subsidiaries and associated companies. These companies are generally focused on one of our projects, and this structure assists in maintaining separate cost centers for these different projects.

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

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

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Our principal activities are oil and gas exploration, development and production, principally in the Republic of Georgia, and to a lesser extent through our minority ownership interest in non-consolidated investees in Kazakhstan. During 2004, we disposed of our oil and gas interests in Ukraine. Also, in 2004, we disposed of our petroleum product marketing and refining activities in Georgia. To date, we continue to direct most of our efforts and resources to the development of our Georgian exploration program, the development of the Ninotsminda Field in Georgia and in the development of the Samgori Field in Georgia (in which we acquired an interest in April 2004).

Exploration, Development and Production Activities

In Georgia our exploration, development and production activities are carried out under five production sharing contracts and agreements (collectively, 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 27,739 acres (113 km^2);

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 388,450 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 will be reduced to 85% following completion of a farm-in by the state oil company, Georgian Oil, to the MK72 well, and potentially to 50% if Georgian Oil exercises its option under that farm-in agreement. CanArgo Norio Limited is now 100% owned by CanArgo following the buy out of minority interests in 2004. This PSA covers an area of approximately 378,523 acres (1,542 km^2); and

4. The Block XI^{G} and XI^{H} Production Sharing Contract (Tbilisi PSC), in which CanArgo Norio Limited owns a 100% interest. CanArgo Norio Limited is now 100% owned by CanArgo following the buy out of minority interests in 2004. This PSC covers an area of approximately 119,843 acres (485 km^2).

5. The Samgori, Block XI^{B} Production Sharing Contract (Samgori PSC), in which CanArgo Samgori Limited owns a 50% interest. CanArgo Samgori Limited is a wholly owned subsidiary of CanArgo. This PSC covers an area of approximately 169,514 acres (634 km^2).

Under production sharing contracts and agreements, 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 States taxes, levies and duties. PSCs are a common form of oil and gas exploration and production contract in many parts of the world.

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Ninotsminda and Samgori Fields

Since completion of the business combination with CanArgo Oil & Gas Inc., our resources have, through our wholly owned subsidiary Ninotsminda Oil Company Limited, been focused on the development of the Ninotsminda Field and related exploration activities. 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. The Ninotsminda Field was discovered later than the Samgori Field and has experienced substantially less development activity. 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 have been advised that Samgori prior to our ownership interest has produced over 180 MMbbl of oil since 1974 at rates of up to 70,000 bopd. Nineteen wells are currently producing from the Samgori complex.

We believe both the Ninotsminda and Samgori PSC areas both outside of and beneath the currently producing reservoirs of these Fields have significant additional exploration potential. To date, we have invested substantial funds in exploring the Ninotsminda PSC area.

Other Projects

We also have additional exploratory and developmental oil and gas properties and prospects in Georgia and we own interests in other oil and gas projects in the former Soviet Union through our minority ownerships investment in non-consolidated investees. During 2004, we disposed of our single remaining Ukrainian asset, the Bugruvativske Field, in order to focus on our business in Georgia. Our principal product is crude oil, and the sale of crude oil and crude oil products is our principal source of revenue.

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Business Structure

CanArgo is a holding company organized under the laws of the State of Delaware and its principal active subsidiaries are as follows:

Background

Ninotsminda PSC

Our activities at the Ninotsminda Field are conducted through Ninotsminda Oil Company Limited, a Cypriot corporation (NOC). Initially we had a partner in NOC named JKX Oil & Gas plc (JKX) however in May 2000, we reached an agreement with JKX to acquire its final interest in NOC. In July 2000, this transaction was completed and NOC became our wholly owned subsidiary.

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NOC (then named JKX Ninotsminda Limited) obtained its rights to the Ninotsminda Field, including all existing wells, one other field 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}. NOC pays 100% of the costs incurred in the project as the sole contractor party under the Ninotsminda PSC. The balance of Production 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 (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 Republic 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.

Until the end of 2001, Georgian Oil had a priority right to receive oil representing a projection of what the Ninotsminda Field would have yielded based upon the wells and equipment in use at the time the contract was entered into. This priority right has now ceased.

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 will be drilled on the Samgori Field. 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 is that the remainder of the drilling program will 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 is due to be completed within 36 months of the commencement of the joint work program, is 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), has 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 is not completed in part within 18 months of the work commencement date (which is expected to be set within the next two months) and completed in full within 36 months of the work commencement date. Furthermore, 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

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Contractor parties respectively. While GOSL and CSL continue to have unrecovered costs, they will receive 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 will receive 30% of Profit Oil (net 15% to us). As with our other PSCs, the allocation of a share of production to the State relieves the Contractor parties of all obligations they would otherwise have to pay the Republic of Georgia for taxes, duties and levies related to activities covered by the Samgori PSC. After NPL s costs are 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 shall 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.

Pursuant to the terms of CanArgo s PSCs in Georgia, including the Ninotsminda and Samgori PSCs, a Georgian not-for-profit company must be appointed as field operator. Until recently, there were four such field operating companies, relating to CanArgo s five 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; The field operator for the Samgori PSC, Ioris Valley Oil and Gas, is currently owned by Georgian Oil and a subsidiary of Georgian Oil, Georgian Oil Samgori Limited, but CanArgo, under its farm-in agreement to the Samgori PSC, has a right to acquire a 50% controlling interest in this company for one US dollar. 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. We are currently in the process of moving the operatorship of the Samgori PSC to a CanArgo controlled company. The field operator provides the operating personnel and is responsible for day-to-day operations. CanArgo or a company within the CanArgo group together with any other contractor party in the contracts such as in the Samgori PSC 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 Georgian Oil believes that any action proposed by us with which Georgian Oil 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.

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The Ninotsminda Field is the easternmost element of an elongate anticline which includes the Samgori and Patardzeuli Fields. The Ninotsminda Field is separated from Patardzeuli by a saddle and a NW-SE trending cross fault. The field structure comprises an elongate 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 fieldwide 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. This well had produced 304,587 barrels of oil to the end of January 2005.

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As a result of this development work, subsequent drilling and the completion of a dynamic reservoir model, it was suggested that a higher level of production could be achieved from the Middle Eocene reservoir from horizontal wells drilled in a preferred orientation so as to intersect the main fracture sets. 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 2005, this well had produced 366,431 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 long term production due to water incursion resulting from, what we believe to be, reservoir damage caused by conventional drilling techniques.

On June 2, 2004, we announced that we had 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 will 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. Although UBCTD is now used commonly in North America, with significant success, these techniques have not yet been applied in the former Soviet Union. However, we believe that these combined drilling technologies will provide the best way to develop and produce both the Ninotsminda and Samgori Fields.

We plan to drill at least five under balanced horizontal sidetracks on the Ninotsminda Field. These include N22H and N30H, which were previously planned to be drilled using conventional drilling techniques. A second horizontal well (N100H2 east horizontal) will be drilled 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. A sidetrack is also being planned from the N49 well. A new well (N99) is included in the program; this well will be designed so as to have more than one horizontal wells drilled from it. These will be drilled into the eastern part of the Field, an area that is currently largely undeveloped. The UBCTD equipment will be utilized to drill only the horizontal section through the reservoir. Preparatory work on the existing vertical wells, including sidetracking and cutting of casing windows for the horizontal wellbores, and the drilling of any new wells will be undertaken by our own operating company using our own drilling rigs and equipment.

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 4½ inch liner. However, technical problems with the equipment caused a number of delays which resulted in the under balance drilling not being completed until late February, 2005. These initial teething problems have now been resolved and it is anticipated that the under balanced drilling in future wells in the program will be completed within a much shorter period. The production interval in the N22H well is approximately 1,148 feet (350 meters). During drilling, sustained gas flow rates of between 20 to 25 MMcf of gas per day were measured using Weatherford s equipment. We believe that this is the biggest gas flow rate ever measured from a well in Georgia to date. At March 14, the well was still undergoing production testing.

The UBCTD unit has now been mobilised to the N100H2 well, in an area of the reservoir which has shown prolific production in the past. Following the experience while drilling N22H certain modifications to the equipment are being made and as such, commencement of drilling on the N100H2 well is not expected before late March 2005. Significant additional work has also been undertaken at other well locations to prepare them for recompletion as horizontal producers. These include the N49 well, which has a surface location very close to N100 and as such requires minimal mobilisation, and the N30 well on the Ninotsminda Field, which are currently shut-in,

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Manavi

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) (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 hydrocarbon bearing sandstones in the Lower Eocene and Palaeocene sequences. Three formation tests were carried out on these sandstones which recovered 35º 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 was of low permeability, or that it suffered substantial formation damage due to the mud used to drill the well. Potential still remains in this sequence but the N100 well was recompleted 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 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).

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 (4,182meters), 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 discovery 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 reservoir unit to 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, 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 and the M11Z sidetrack is currently at a depth of 12,461 feet (3,798 meters). Drilling in this section is complicated by the presence of extremely over-pressured swelling clays, and these continue to cause drilling problems for our equipment. After extensive technical analysis and discussions with the international drilling contractor Saipem S.p.A. (Saipem), and

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with a major drilling mud company it has been decided that the optimum way to sidetrack this well to the top of the reservoir as planned will be 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). As described below, we have already concluded an agreement with Saipem to provide a rig and drilling services to the company. It is expected that the sidetrack will be completed in a more effective manner utilising this new equipment. It is now planned to sidetrack the well with the Saipem rig to the top of the reservoir sequence at 13,633 feet (4,155 meters) where a 5-inch casing will be set. The Saipem rig is currently being mobilised to Georgia and should be ready to re-commence drilling of the sidetrack by the middle of April. The conventional drilling operations are expected to be completed by the middle of May, after which Weatherford will take over using the UBCTD unit to drill down into the Cretaceous and fully evaluate the oil discovery.
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. On June 22, 2004, we announced that our operating subsidiary in Georgia had signed a contract with Great Wall Drilling Company (GWDC) of China to supply drilling services for the drilling of a first appraisal well (M12) on the Manavi oil discovery with an option to drill further wells. However, due to an unacceptable delay in mobilising the rig to Georgia, on January 28, 2005, we signed an alternative contract with Saipem.

Under the terms of the contract, Saipem will supply an Ideco E-2100 Az drilling rig complete with crew to drill the Manavi 12 appraisal well to an approximate depth of 16,400 feet (5,000 meters) in the Cretaceous. The contract includes an option to drill further wells. The rig and associated equipment is currently being mobilised from Astrakhan in southern Russia to Georgia where it will now first complete the M11Z sidetrack. In order to expedite the Manavi appraisal program, we plan to drill and set surface casing on the M12 well while Saipem first complete the M11Z sidetrack, thereby minimising any delay in the appraisal of this potentially important discovery.

The M12 location is approximately 4 km to the west of the Manavi M11 Cretaceous oil discovery well, and located on seismic data acquired by CanArgo in 1998.

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.

With respect to gas production, only limited short duration gas supply contracts currently exist for production directly from the gas cap. Gas currently produced from the Middle Eocene and upper zones is subject to market conditions and environmental constraints within Georgia and the ability of NOC to arrange short-term gas supply agreements as required.

West Rustavi and Kumisi

In addition to the Ninotsminda Field and Manavi prospect, under the Ninotsminda PSC, NOC has rights to one other field, West Rustavi and an underlying gas prospect named 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 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 by NOC over this structure, but further geo-technical work is required on this horizon to determine its potential size, which could be significant. Given a positive outcome from this work,

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NOC has potential plans to appraise this discovery dependent on this technical work and on commercial sales contracts for gas off take.

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.

Samgori

The Samgori Field complex is the largest field discovered to date in Georgia. It was discovered in 1974, when oil was produced from the Middle Eocene fractured volcanoclastic sequence in the Samgori area. Further exploration resulted in the discovery in 1975 of the Patardzeuli extension to the east, and subsequently in 1979 of the South Dome accumulation. Production of the high quality low sulphur crude increased, focused initially on Samgori, then on Patardzeuli, with peak production reaching over 70,000 bopd in 1981. The primary reservoir in the Samgori complex is the Middle Eocene as in the Ninotsminda Field, with additional potential in the Upper Eocene and Lower Eocene. However, the reservoir is somewhat thicker than in Ninotsminda on average approximately 2,200 feet thick (670 meters) and having better porosity and permeability. Samgori oil is sweet and light (38.9^{o} API) having very similar characteristics to Ninotsminda crude but unlike Ninotsminda there is no gas cap. The state company Georgian Oil originally operated the field and in the latter years of the Soviet regime production dropped off rapidly falling to almost nothing over the period to 1998.

In October 1995, National Petroleum Limited (NPL) signed an agreement with Georgian Oil to further develop the Samgori Field complex, and to explore the surrounding licence Block XI^{B}. Under the original joint venture the commercial terms were extremely tough for NPL, and this was subsequently re-negotiated in the form of a production sharing contract. This followed the Georgian Petroleum Law which came into force in 1999 and in 2001 NPL signed a new Production Sharing Contract with a much more appropriate commercial structure. Despite this, no further significant work was carried out and field production stood at approximately 700 bopd at the end of 2003. Georgian Oil Samgori Limited (GOSL), a wholly owned subsidiary of Georgian Oil, acquired NPL s interest in the PSC in December 2003, but with NPL having an option to reclaim their interest in the event that an Agreed Work Programme was not carried out. In addition NPL have the right to recover their previous costs from a portion of GOSL s net profits, and retain a small net profit interest. It is this agreement that we farmed into in January 2004.

Within the Samgori PSC area there are several identified prospects and discoveries in other horizons, notably the Upper Eocene, Lower Eocene and Cretaceous. Independent evaluations carried out previously indicate significant potential, not only in the Samgori Field itself, but also in other discoveries and prospects in the large block. These include the Krtsanisi Middle Eocene oil discovery, the Rustavi gas/condensate discovery and the West Teleti and Varketili Lower Eocene/Palaeocene gas discoveries. As this acreage lies adjacent to other CanArgo licence areas, the potential of this Block will be integrated into an overall exploration / appraisal programme with our existing discoveries and prospects, involving further seismic acquisition and appraisal/exploration drilling.

On August 2, 2004 we announced that we had commenced drilling operations on a new Samgori Field development well (S302), the first new well to be drilled on the field for several years. The well which was targeting a previously undrilled area of the field was drilled to a total depth of 7,776 feet (2,370 meters) in mid-October 2004 having encountered moveable oil in the Middle Eocene reservoir. The well will be completed with one or more horizontal sidetracks utilising the UBCTD unit. Completion of this well at our cost fulfilled our farm-in obligations under our agreement with GOSL.

As with our existing producing Ninotsminda Field, it has been recommended that future horizontal wells should be drilled under balanced on the Samgori Field complex, utilising coiled tubing. It is expected that such techniques will result in more efficient production, longer horizontal sections, and less chance of causing damage to the reservoir. It is planned to drill up to 10 horizontal sections from existing vertical wells or new well bores. This will be undertaken as part of an integrated development program planned for both the Ninotsminda and Samgori Fields under the Weatherford UBCTD contract described above. In the meantime, work is going on to extend the Ninotsminda dynamic reservoir model to include the Samgori complex which will be used to identify the under balanced drilling locations.

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ITEM 2. PROPERTIES

Production History

The Ninotsminda Field was discovered and initial development began in 1979. Current gross field production as of March 11, 2005 was approximately 640 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]
2004	370,176	241,131	65,066	42,293
2003	695,174	451,863	108,630	70,610
2002	292,289	189,988	212,499	138,124

(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.

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. The gross field production as of March 11, 2005 was approximately 530 bopd. The gross and net production for the nine month period ending December 31, 2004 was as follows:

Year Ended December 31,	Oil (Barrels) Gross	Oil (Barrels) Net (PSC Entitlement)[2]	CSL Net Share
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 owns 50% of the contractor s interest in the PSC. As a result of CanArgo s interest in CSL, these volumes accrue to the benefit of CanArgo for the recovery of capital, repayment of operating costs and share of profit.

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Productive Wells and Acreage

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

	Gross	
	Number of Wells	Acres
Ninotsminda Field	11	492

On December 31, 2004, there were no 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 is presented on a net basis representing our 100% interest in CSL which in turn has a 50% interest in the Samgori PSC.

	Net	
	Number of Wells	Acres
Samgori Field Complex	11.5	950

Reserves

The following table summarizes net hydrocarbon reserves for the Ninotsminda Field. This information is derived from a report dated as of January 1, 2005 prepared by Oilfield Production Consultants (OPC), independent petroleum consultants headquartered in London, England. This report is available for inspection at our principal executive offices during regular business hours. The reserve information in the table below has also been filed with the Oslo Stock Exchange.

Oil Reserves	**Oil Reserves - Gross (Million Barrels)**	**PSC Entitlement Volumes(1) (Million Barrels)**
Proved Developed	3.264	2.122
Proved Undeveloped	3.007	1.954
Total Proven	6.271	4.076

Gas Reserves	Gas Reserves - Gross (Billion Cubic Feet)	PSC Entitlement Volumes (1) (Billion Cubic Feet)
Proved Developed	1.462	0.950
Proved Undeveloped	1.158	0.753
Total Proven	2.620	1.703

(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.

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

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

Uncertainties exist in the interpretation and extrapolation of existing data for the purposes of projecting the ultimate production of oil from underground reservoirs and the corresponding future net cash flows associated with that production. The estimating process requires educated decisions relating to the evaluation of all available geological, engineering and economic data for each reservoir. The amount and timing of cost recovery is a function of oil and gas prices which can fluctuate significantly over time. The oil price used in the report by OPC as of January 1, 2005 was $27.16 per barrel based on the net price per barrel received by NOC in December 2004. The net gas price is $1.27 per mcf. 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 have independent reserves been assessed for the Samgori Field complex as the original Contractor party to the Samgori PSC, NPL, has 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 which includes the drilling of 10 horizontal well sections is not completed in accordance with the agreement NPL concluded with GOSL in December 2003. We are committed to this work program through our farm-in agreement with GOSL dated January 8, 2004. On completion of the agreed work program, we would aim to book reserves for the Field which are properly attributable to us. In the meantime, we will continue to benefit from our share of production.

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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, 2004. 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 current 50% interest in the Samgori Block XI^B contract through our wholly owned subsidiary CSL.

	Gross		Net	
PSC	**Acres**	**Square Kilometers**	**Acres**	**Square Kilometers**
Ninotsminda, Manavi and West Rustavi covering Block XI^E	27,739	113	27,739	113
Nazvrevi and Block XIII	388,450	1,572	388,450	1,572
Norio (Block XI^C) and North Kumisi.	378,523	1,542	378,523	1,542
Block XI^G and XI^H	119,843	485	119,843	485
Samgori	169,514	634	84,757	317
Total	1,084,069	4,346	999,312	4,029

We lease office space in London, England; Guernsey, Channel Islands; and Tbilisi, Republic of Georgia. The leases have remaining terms varying from nine months to five years and six months and annual rental charges ranging from $24,000 to $300,000.

Processing, Sales and Customers

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 and CSL now use that infrastructure, including initial processing equipment.

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 eleven kilometers either in a pipeline or by truck to Georgian Oil s central processing facility at Sartichala for further treatment. The gas is transported to Sartichala in a separate pipeline where some is used for fuel and the rest is either piped 34 kilometers to Rustavi where it is delivered to the Rustavi industrial complex for sale to a number of customers or delivered to the neighbouring communities. Oil produced from the Samgori Field complex is 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 transfers it by pipeline 20 kilometers to a railhead at Gatchiani or by road tanker to Vaziani rail loading terminal primarily for export sales. At the railheads, the oil is loaded into railcars for transport to the Black Sea port of Batumi, Georgia, where oil can be loaded onto tankers for international shipment. Buyers transport the oil at their own risk and cost from the delivery point at Sartichala.

NOC sells its oil directly to local and international buyers. In 2004, NOC sold its oil production in accordance with the terms of sales agreements concluded with Sveti Limited and Primrose Financial Group which included the sale of oil to customers nominated under these agreements. During the year, oil was purchased and paid for by a total of 14 customers. Of these customers, the following four customers represented sales greater than 10% of oil revenue:

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Customer	Percent of Oil Revenue
Crownhill	27.5%
Gero	21.9%
Interchem Energy	20.7%
Viva	11.6%

Management believes that the loss of any of the foregoing 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 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%

In 2002, NOC sold its oil production to eight customers of which the following four customers represented sales greater than 10% of oil revenue:

Customer	Percent of Oil Revenue
Caspian Trading	28.4%
Sveti	26.4%
Crownhill	20.1%
Trafigura	19.9%

For NOC, sales to both the domestic and international markets during 2004 were based on the average of a number of quotations for Dated Brent Mediterranean or Urals Mediterranean with the latter being used when the monthly quantity of oil available under the Primrose Financial Group Agreement was less than 7,000 metric tonnes (approximately 53,060 barrels) per month with an appropriate discount for transportation and other charges. 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 and 2002 were $7.70 and $5.09 respectively. The higher discount in 2003 and 2004 is due to significant upfront non-interest bearing security payments being made by the buyer to NOC in return for the option to lift oil over a twelve-month period which was later extended for a further period (described more fully under Item 7. Management s Discussion and Analysis of Financial Condition and Operations Liquidity and Capital Resources). For the period of the option, NOC will retain the security for its own use and account.

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

Year Ended December 31,	Average Sales Price Oil $/boe	Gas $/mcf	Unit Production Cost $/boe
2004	24.94	1.41	5.81
2003	20.07	1.25	2.59
2002	17.09	1.25	4.69

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Since April 2004, when CSL acquired an interest in the Samgori PSC, 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 to December 31, 2004:

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 period April to end-December 2004 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 2004 was $5.12 per barrel. There were no prior year sales made by CSL.

The average sales price and the average production cost per unit of oil and gas produced by CSL in 2004 was as follows:

Year Ended December 31,	Average Sales Price Oil $/boe	Average Sales Price Gas $/mcf	Unit Production Cost $/boe
2004	33.96	0.00	9.59

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

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

Other Georgian Production Sharing Contracts

Nazvrevi and Block XIII Production Sharing Contract (Nazvrevi PSC   )

In February 1998, we 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 492, 914 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 388,450 acres (1,572 km^2).

Under the Nazvrevi PSC, we pay 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 (profit 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 is allocated on a 50/50 basis

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between Georgian Oil and CanArgo. 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 CanArgo, 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 Republic of Georgia for taxes and similar levies related to activities covered by the production sharing contract. Both Georgian Oil and CanArgo 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 continue to be interpreted, with a view towards defining possible oil and gas prospects and exploration drilling locations. 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 we have met the requirements of the work program defined in the production sharing agreements. The Manavi oil discovery may extend into the Nazvrevi PSC area and the Kumisi gas discovery may extend into Block XIII, 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.

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 378,523 acres (1,542 km^2) 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. 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. Downhole seismic data acquired in the well bore indicated the target may be at a depth of approximately 13,780 feet (4,200 meters), and CNL did not have sufficient funding to complete the well to that depth. However 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 obligates Georgian Oil to pay up to $2.0 million to deepen, to a planned depth of 16,733 feet (5,100 meters) the MK-72 well in return for a 15% interest in the contractor share of the Norio PSA. Georgian Oil also has an option (the Option), exercisable for a limited period after completion of the well, to increase its interest to 50% of the contractor share of the Norio PSA on payment to CNL of US$ 6.5 million. If Georgian Oil exercises this Option under the farm-in agreement, it loses its rights to exercise the PSA Option under the Norio PSA itself.

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. CNL is now a wholly owned subsidiary of CanArgo. In the event that Georgian Oil exercises the Option and pays the required $6.5 million, we will receive this payment in full. If Georgian Oil exercises this Option we will issue a further 3 million restricted shares to the minority interest holders.

Drilling at the MK72 well, funded by Georgian Oil, recommenced in December 2003 and the well was drilled ahead to a depth of 14,830 feet (4,520 meters). The well is now 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 15 to 20%. From the oil shows while drilling and log analysis, these sands appear to be oil bearing. It is planned to test the Oligocene sands once the well has reached total depth. Data obtained from a vertical seismic profile run in the well indicates that there is a seismic reflector some 984 feet (300 meters) below the current depth of the well which may be the primary target. The well is currently suspended and it is planned to recommence drilling activities as soon as one of our drilling crews, who are presently engaged in our under balanced coiled tubing drilling operation on the Ninotsminda Field, and in the drilling of the Manavi M11Z sidetrack becomes available.

The Norio PSA covers a large exploration area with what management believe to be good oil and gas potential. 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.

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 119,843 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. We view these blocks as having good potential, being adjacent to productive acreage and with some existing wells on the blocks. 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 four years is $350,000. The above mentioned Georgian Oil farm-in to the Norio PSA does not apply to the Tbilisi PSC.

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

Refining and Other Activities

We also engage in other oil and gas activities in Georgia and elsewhere. [Segment and geographical information including revenue from continuing operations from external customers, operating profit (loss) from continuing operations and total assets is incorporated herein by reference from note 18 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 under balanced coiled tubing drilling program on the Ninotsminda and Samgori Fields.

We also own a mobile 3-megawatt duel fuel power plant which we have entered into an agreement to sell for $600,000 and have received a non-refundable deposit of $300,000. The unit is currently in the United States where it was under-going tests in late 2004. On completion of these tests to the satisfaction of the buyer, we will transfer title for this equipment and receive the final payment of $300,000. We expect this transaction to be finalized during the first quarter of 2005. This asset is classified and reflected in our financial statements in   Assets held for sale   for all periods presented.

In September 2001, we entered into an agreement to provide drilling services to a third party using one of our rigs. Commercial drilling operations commenced in October 2001 and continued through February 2002. We subsequently established a wholly owned well services subsidiary (Argonaut Well Services Limited) and at the end of March 2003 concluded a new drilling service contract with an operating company in Georgia. Due to the level of activity on our properties in Georgia, our equipment has been fully utilised throughout 2004, and we have not bid in any further tenders for drilling contracts.

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Potential 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 have fully impaired our $75,000 investment in the Caspian exploration project as of September 30, 2004.

Potential Kazakhstan Project

In December 2003, we announced details of the acquisition of oil and gas interests in Kazakhstan which were previously owned by the UK public company Atlantic Caspian Resources plc (ACR) through a specially established associated company, Tethys Petroleum Investments Limited (TPI) which we have a 45% non controlling ownership acquired a 70% interest in BN Munai LLP (BNM), a Kazakh limited liability partnership on certain conditions being satisfied.

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

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

On June 8, 2004, we announced that that deal has now been finalised with the registration of CanArgo s interest in BN Munai LLP (BNM). We have acquired this interest through TPI in which we are currently a 45% shareholder. TPI s wholly owned subsidiary Tethys Kazakhstan Ltd (TKL) has now become officially registered as the owner of a 70% interest in BNM. Negotiations are ongoing with the Kazakh authorities regarding the Kyzyloy production licence.

Under ACR s ownership BNM drilled two deep exploration wells in the Akkulkovsky area over the past four years, these wells being plugged and abandoned with hydrocarbon shows. However, we believe that the short term potential may lie in the shallower Kyzyloy Gas Field. This is a discovered shallow gas field is located close to the main Bukhara Urals gas pipeline system, and the Bazoy gas storage and compression facility. Additional, shallow gas indicators are apparent on seismic data, which potentially could be added to any development of the Kyzyloy

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Field. Financing by TPI of this project is intended to come primarily from third party investment into TPI or directly into the project, with no significant funding planned to come from us.

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 19 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, 2005, 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, CanArgo signed a sales agreement disposing of a 3-megawatt duel fuel power generator for $600,000. Following receipt of a non-refundable deposit of $300,000, the unit was shipped to the US for testing. The test was

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completed at the beginning of 2005 and we expect the generator will be delivered to the buyer in the near future following receipt of the final payment.

Employees

As of December 31, 2004, we had 158 full time employees. Of our full time employees, the entity acting as operator of the Ninotsminda Field for Ninotsminda Oil Company has 139 full time employees, and substantially all of that company s activities relate to the production and development of the Ninotsminda Field. We have not experienced any strikes, work stoppages or other labour disputes and management believes the Company s relations with its employees are satisfactory.

Risks Associated with CanArgo s Activities

Reference is hereby made to the Section entitled QUALIFYING STATEMENT WITH RESPECT TO FORWARD-LOOKING INFORMATION with respect to certain qualifications regarding the following information

CanArgo s 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 reducing costs, generating funds from internal sources including the sale of certain non-core assets, 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, additional funding and/or proceeds from the sale of non-core assets received meet our cash flow needs. If these operating cash flows, additional financings, are not in accordance with our expectations, adjustments may have to be made to our business plan which will limit our development and exploration activities.

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. We believe that we will be able to generate funds from quasi-governmental financing agencies, conventional lenders, equity investors and other oil and gas companies that may desire to participate in our oil and gas projects. In February 2004, we announced that we had signed a Standby Equity Distribution Agreement that allows us, at our option, to issue shares to US-based investment fund Cornell Capital Partners LP up to a maximum value of $20,000,000 over a period of up to two years from the date on which the Registration Statement on Form S-3 registering for resale the shares under the Securities Act of 1933, as amended (Securities Act) is declared effective. The Registration Statement was declared effective by the SEC on February 3, 2005. Also, on September 22, 2004 we announced that we had completed a global public offering (Global Offering) of 75 million shares of our common stock at a purchase price of $0.50 per share. We raised $37,500,000 in gross proceeds and $35,250,000 in net proceeds after the payment of commissions but before the payment of the expenses of the Global Offering aggregating $4,095,107.

Current Operations Dependent on Success of the Ninotsminda and Samgori Fields and Georgian Exploration

Until recently, we have directed substantially all of our efforts and most of our available funds to the development of the Ninotsminda Field in the Republic of Georgia, exploration in that area and some ancillary activities closely related to the Ninotsminda Field project. This decision is based on management s assessment of the potential of the Ninotsminda Field area and the surrounding areas including the Samgori Field area in which we acquired an interest in 2004. However, the company s focus on the Ninotsminda Field has over the past several years resulted in overall losses for us and we have yet to be profitable. There can be no assurances that the exploration and development plans for the Ninotsminda Field and the Samgori Field will be successful. For example, these Fields may not produce sufficient quantities of oil and gas to justify the investments made and the planned future investments for the Fields, and we may not be able to produce the oil and gas at a sufficiently low cost or to market the oil and gas produced at a sufficiently high price to generate a positive cash flow and a profit. Our Georgian exploration and appraisal program is an important factor for future success and this program may not be successful, as it carries substantial technical risk.

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Write Off of 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.

Possible Inability to Finance Present Oil and Gas Projects

Our ability to finance all 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 could require us to scale back or abandon part or all of our project development, capital expenditures, production and other plans. Apart from the evaluation of the economics of specific investment proposals, 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 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 also be influenced by their evaluations of us and our projects, including their technical difficulty, and the comparison with available alternative investment opportunities.

Additional Funds Needed For Long-Term Oil and Gas Development Plans

It will take many years and substantial cash expenditures to develop fully our oil and gas properties. The company generally has the principal responsibility to provide financing for its oil and gas properties and ventures. Accordingly, we need to raise additional funds from outside sources in order to pay for project development costs beyond those currently budgeted through 2005. We may not be able to obtain that additional financing, or such funds may only be available on commercially unattractive terms. If, in either such case, adequate funds are not available, it will be necessary to scale back or even suspend operations. The carrying value of the Ninotsminda Field may not be realized unless additional capital expenditures are incurred to develop the Field. Furthermore, additional funds will be required to pursue exploration activities on our existing undeveloped properties. While expected to be substantial, without further exploration work and evaluation the amount of funds needed to fully develop all of our oil and gas properties cannot at present, be quantified.

Oil and Activities Involve Risks, Many of Which Are Beyond Our Control

Our exploration, appraisal, development and production activities are subject to a number of factors and risks, many of which may be beyond our control. First, we must successfully identify commercial quantities of oil and gas. The exploration and 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, equipment and personnel to support operations;

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- local and global oil prices; and
- government regulation and legal uncertainties.

The company s activities can also be affected by a number of hazards, such as:

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

Any of these hazards could result in damage, losses or liability for the company. 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 former Soviet Union. We do not purchase insurance covering all of the risks and hazards that are involved in oil and gas exploration, development and production.

Risk of Political Instability with Respect to Foreign Operations

Our principal oil and gas properties and activities are in the Republic of Georgia, which is located in the former Soviet Union. Operation and development of these assets is subject to a number of conditions endemic to former Soviet Union countries, including political instability. The present governmental arrangements in the former Soviet Union in which we operates 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 themselves replace these governments. Our operations typically involve joint ventures or other participatory arrangements with the national government or state-owned companies.

The Ninotsminda PSC 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, 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. We are not insured against such political risks because management deems the premium costs of such insurance to be currently prohibitively expensive.

Risk of Social, Economic and Legal Instability

The political institutions in the countries which comprise the former Soviet Union have recently become more fragmented, and the economic institutions of many of these countries have only recently converted to a market economy from a planned economy. New laws have been introduced, and the legal and regulatory regimes in such regions are often vague, containing gaps and inconsistencies, and are constantly 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 following:

- uncertainty as to the enforceability of contracts;
- sudden or unexpected changes in demand for crude oil and or natural gas;
- the lack of trained personnel; and

- the lack of equipment and services and the presence of other factors that could significantly change the economics of production.

Social, economic and legal instability have accompanied these changes due to many factors which include:

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

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This instability can make continued operations in affected regions difficult or impossible.

Inadequate or Deteriorating Infrastructure in the Former Soviet Union

Countries in the former Soviet Union often either have underdeveloped infrastructures or, as a result of shortages of resources, have permitted infrastructure improvements to deteriorate. The lack of necessary infrastructure improvements can adversely affect operations. For example, the lack of a reliable electrical power supply caused NOC to suspend drilling of one well and the testing of a second well during the 1998-1999 winter season, although the availability of electrical power supplies has been more regular since that time.

Currency Risks in the Former Soviet Union

Payment for oil and gas products sold in the 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. Although most former Soviet Union country currencies are presently convertible into U.S. dollars, there is no assurance that 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 the 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. The company 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.

Tax Risks in the Former Soviet Union

Countries in the former Soviet Union frequently 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, 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 agreements in Georgia and all current taxes are payable from the State s share of petroleum produced under the production sharing contracts.

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 those of the company and may conflict with our interests. Unless we are able to compromise these conflicting objectives and interests in a mutually acceptable manner, agreements and arrangements with these third parties will not be consummated.

We may not have a majority of the equity in the entity that is the licensed developer of some projects, that we may pursue in the former Soviet Union, even though we may be the designated operator of the oil or gas field. In such circumstances, the concurrence of co-ventures may be required for various actions. Other parties influencing the timing of events may have priorities that differ from ours, even if they generally share the same objectives. Demands by or expectations of governments, co-venturers, customers, and others may affect our strategy regarding the various projects. Failure to meet such demand or expectations could adversely affect our participation in such projects or its ability to obtain or maintain necessary licenses and other approvals.

Demands by or expectations of governments, co-venturers, customers and others may also affect our strategy regarding 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.

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Governmental Registration

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

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

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.

Oil and Gas Production Could Vary Significantly From Reserve Estimates

Oil and natural gas reserves and their values as determined by petroleum engineers are estimates only. Proved oil and gas reserves are the estimated quantities of natural gas and crude oil reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under period-end economic and operating conditions. 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, transport and market 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 most recent report on our oil and gas reserves prepared by OPC as of January 1, 2005. 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.

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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 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.

Competition

The oil and gas industry is highly competitive. Our competitors include integrated and independent oil and gas companies. Many of our competitors are large, well-established, well-financed companies. Because of our small size and our lack of financial resources, we may not be able to compete effectively with these companies.

Operations are Dependent on Chairman of the Board and Chief Executive

Dr. David Robson, the Chairman of the Board, President and Chief Executive Officer of CanArgo, is our executive who has the most experience in the oil and gas industry and who has the most extensive business relationships in the former Soviet Union. Our business and operations could be significantly harmed if Dr. Robson were to leave the company or become unavailable because of illness or death. Dr. Robson through his company, Vazon Energy Limited, has signed a comprehensive Management Services Agreement with a rolling six-month notice period and a two-year non-competition clause effective from the date of termination of the agreement. We do not carry key employee insurance on any of our employees.

ITEM 3. LEGAL PROCEEDINGS

At December 31, 2004 there were no legal proceedings pending involving CanArgo which, if adversely decided, would have a material adverse effect on CanArgo s financial position or 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, 2004.

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PART II

ITEM 5. MARKET FOR COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

CanArgo is listed on the AMEX where our common stock trades under the symbol CNR and on the Oslo Stock Exchange (OSE) where our 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, 2003	0.11	0.03	35,575	0.06	0.04	273,079			
June 30, 2003	0.22	0.05	41,739	0.24	0.05	1,127,948			
September 30, 2003	0.47	0.10	29,714	0.49	0.16	1,936,776			
December 31, 2003	0.69	0.26	107,109	0.54	0.27	1,582,019			
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

* 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 11, 2005, the closing price of our common stock on the AMEX and the OSE was $1.70 and $1.71, respectively.
On March 11, 2005 one U.S. dollar equalled 6.09 Norwegian kroner.

On March 11, 2005 the number of holders of record of our common stock was approximately 12,500. 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.

In the fourth quarter of 2004, 60,000 stock options were issued to employees under the 2004 Long Term Stock Incentive Plan.

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ITEM 6. SELECTED FINANCIAL DATA

Reference is hereby made to the Section entitled QUALIFYING STATEMENT WITH RESPECT TO FORWARD-LOOKING INFORMATION 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,				
	2004	**2003**	**2002**	**2001**	**2000**
Financial Performance					
Operating revenues from continuing operations	9,574	8,105	5,486	4,575	7,010
Operating loss from continuing operations	(2,954)	(159)	(4,902)	(11,838)	(2,401)
Other income (expense) and Minority Interest in income (loss) of consolidated subsidiaries	(2,346)	(597)	(576)	(525)	258
Net loss from continuing operations	(5,300)	(756)	(5,478)	(11,313)	(2,143)
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	(4,757)	(7,322)	(5,328)	(13,218)	(2,151)
Net loss per common share basic and diluted before cumulative effect of change in accounting principle from continuing operations	(0.04)	(0.01)	(0.06)	(0.14)	(0.04)
Net loss per common share basic and diluted before cumulative effect of change in accounting principle from discontinued operations	(0.04)	(0.07)	(0.00)	(0.02)	(0.00)
Net loss per common share basic and diluted	(0.04)	(0.08)	(0.06)	(0.16)	(0.04)
Cash generated by (used in) operations	(3,781)	4,431	1,635	(6,289)	7,881
Working capital	23,952	3,890	10,646	14,590	23,315
Total assets	105,160	73,360	70,736	70,312	82,849

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Reported in $000 s except for per common share amounts	Year Ended December 31,				
	2004	**2003**	**2002**	**2001**	**2000**
Minority shareholder advances				450	
Stockholders equity	96,821	56,708	62,105	65,800	72,426
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. CSOP was purchased in 2000 and operations were developed in 2001, therefore prior to 2000 there is no effect on the financial statements in respect of discontinued operations.

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 Qualifying Statement With Respect To Forward-Looking Information 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 Business-Risks Associated with CanArgo s Activities 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 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

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Year end gross total proved oil reserves at the Ninotsminda Field were 6.271 MMbbl down 7% from 2003 s 6.762 MMbbl. Over the same period, gross total proved natural gas reserves, on an energy equivalent basis, decreased from 0.51 MMboe to 0.44 MMboe.

Because our proved reserves will decline as crude oil, and, to a lesser extent, natural gas and natural gas liquids are produced (since our natural gas and natural gas liquid production is currently incidental to our crude oil production), 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. We did acquire an interest in the Samgori Oil Field in April 2004, but as the original Contractor party to the Samgori PSC, NPL, has 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 which includes the drilling of 10 horizontal well sections is not completed in accordance with the agreement it concluded with GOSL in December 2003. We are committed to this work program through our farm-in agreement with GOSL dated January 8, 2004. On completion of the agreed work program through the implementation of our under balanced coiled tubing drilling program on the Samgori Field, we would aim to book reserves for the Field which are properly attributable to us. In the meantime, we will continue to benefit from our share of production. For more information on the volumes of crude oil, natural gas liquids and natural gas we have produced during 2002, 2003 and 2003, please refer to the information under the caption Results of Operations below.

Exploitation and Development Activity

In 2004, we continued exploitation activities on our Georgian properties. Following our acquisition of a 50% interest in the Samgori production sharing contract including the Samgori Oil Field which is adjacent to our Ninotsminda Field, our efforts during 2004 focused on a joint field development program for the Ninotsminda and Samgori Fields. In June 2004, we signed a contract with WEUS Holding Inc., a subsidiary of Weatherford International, Ltd, to supply Under Balanced Coiled Tubing Drilling (UBCTD) services to our projects in Georgia for a program of up to 14 horizontal wells. In preparation for this work, we acquired, in advance, an 18,387 feet (5,600 meter) $2^{7/8}$ inch custom built coiled tubing string and drop-in-drum, back-up coil and drum, drill strings and liners in addition to other ancillary equipment. At the same time, a number of existing vertical wells on the Ninotsminda Field including N22, N100, N49 and N30 have been prepared by our operating company using our own drilling rigs and equipment for horizontal recompletion using UBCTD. At the end of the year, UBCTD operations had commenced on the Ninotsminda N22 well. On the Samgori Field, we participated in the drilling of one new vertical well, S302. This well was successfully drilled to the Middle Eocene reservoir and it is planned to recomplete this well with one or more horizontal sidetracks utilizing the UBCTD equipment. We invested $8.3 million in capital spending on these activities during 2004.

We have budgeted approximately $12 million for under balanced drilling expenditures on the Ninotsminda and Samgori Fields in 2005.

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

Exploration and Appraisal

On Manavi, the sidetrack on the M11 Cretaceous oil discover is proceeding slowly due to significant drilling problems related to extremely over-pressured swelling clays in the section above the reservoir, and these continue to cause drilling problems for our equipment. After extensive technical analysis and discussions with the international Italian drilling contractor Saipem, and with a major drilling mud company it has been decided that the optimum way to sidetrack this well to the top of the reservoir as planned will be 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). We concluded an agreement with Saipem in January 2005 to provide a rig and drilling services to the company to drill an appraisal well on the Manavi structure,

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but now Saipem will first drill the M11Z sidetrack. It is expected that the sidetrack will be completed in a more effective manner utilising this new equipment. It is now planned to sidetrack the well with the Saipem rig to the top of the reservoir sequence at 13,633 feet (4,155 meters) where a 5-inch casing will be set. The Saipem rig is currently being mobilised to Georgia and should be ready to re-commence drilling of the sidetrack by the middle of April. The conventional drilling operations are expected to be completed by the middle of May, after which Weatherford will take over using the UBCTD unit to drill down into the Cretaceous and fully evaluate the oil discovery. On completion of drilling of M11Z, Saipem will mobilize its rig to the M12 appraisal well location. We also plan to put in place a production facility so as to enable us to put the wells, if successful, on early production.

Drilling at the MK72 exploration well, funded by Georgian Oil, recommenced in December 2003 and the well was drilled ahead to a depth of 14,830 feet (4,520 meters). The well is now cased, having encountered oil bearing sands in the Oligocene formation. It is planned to test these sands on completion of the well. Data obtained from a vertical seismic profile run in the well indicates that there is a seismic reflector some 984 feet (300 meters) below the current depth of the well which may be the primary target. The well is currently suspended and it is planned to recommence drilling activities as soon as one of our drilling crews, who are presently engaged in our under balanced coiled tubing drilling operation on the Ninotsminda and Samgori Fields, becomes available.

In 2005, we have budgeted approximately $20 million primarily for the appraisal of the Manavi discovery.

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

- funding of the joint 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;

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raising of additional capital;

achieving significant production at costs that provide acceptable margins;

reasonable levels of taxation, or economic arrangements in lieu of taxation in host countries; and

the ability to market the oil and gas produced at or near world prices.

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

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, funding from the sale of our equity securities under a Standby Equity Distribution Agreement with Cornell Capital (the Cornell Equity Facility) described below, 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 11, 2005, the Company had an aggregate of 197,766,338 shares of common stock outstanding. On March 23, 2004, shareholders approved an increase in the authorized number of shares of common stock from 150,000,000 to 300,000,000. During 2004, we issued 89,594,101 shares of which 75,000,000 shares were in connection with a global public offering which closed September 22, 2004 thus leaving an aggregate of 52,875,892 of uncommitted shares available for future issuance by the Company after a reservation of an aggregate of 52,005,603 shares for issuance under various stock option plans, warrants and other contractual commitments.

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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, funding under the Cornell Equity Facility 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.

As of December 31, 2004, we had working capital of $23,952,000, compared to working capital of $3,890,000 as of December 31, 2003. The $20,062,000 increase in working capital from December 31, 2003 to December 31, 2004 is principally due to the $37,500,000 gross proceeds received from the global public offering of 75 million shares of our common stock in September 2004 along with on going cash flows from our Georgian operations, the receipt during the period of a further $1,857,000 payment from the agreed sale of our interest in our retail operation, CanArgo Standard Oil Products Limited, and $250,000 from the disposal of our interest in the Bugruvativske Field in Ukraine partially offset by expenditures in the period to fund the cost of preparing wells for our horizontal development program at the Ninotsminda and Samgori Fields in Georgia and further drilling of the Norio exploration well and to fund our operating losses.

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 deliver 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. Following receipt of a non-refundable deposit of $300,000, the unit was shipped to the US for testing. The test was completed at the beginning of 2005 and we expect the generator will be delivered to the buyer in the near future following receipt of the final payment.

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.

Cornell Equity Facility

On February 11, 2004, we entered into a Standby Equity Distribution Agreement (Agreement) 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 Agreement, Cornell Capital will provide us with an equity line of credit for 24 months. The maximum aggregate amount of the equity placements pursuant to the Agreement is $20,000,000. Subject to this limitation, we can draw down up to $600,000 in any seven-day 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 of 1933, as amended (Securities Act). Shares issued to Cornell Capital would be 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 Agreement, Cornell Capital will receive a substantial discount to the current market price of CanArgo common stock. The level of the total discount will vary depending on the market price of our stock and the amount drawn down under the Agreement. 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 receive a total discount of 13.87% to the market price of our stock. Such discount will comprise (1) 3% discount to, the lowest volume weighted average price of our common stock; (2) 5% of the proceeds that we receive for each advance under the Agreement; and (3) a commitment fee of 5.87%. The commitment fee, which has been 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 represents nearly 4% of the estimated 23 million shares of common stock that may be issued by us under the Agreement. The amount of each advance is subject to a maximum of $600,000 per advance, with a minimum of seven trading days between advances. 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 have been included in the Registration Statement on Form S-3 (Reg. No. 333-115261) filed on May 6, 2004. On February 03, 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 shall be 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 is declared effective. If the promissory note is not repaid in full when due, interest shall accrue 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 will 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 advance 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 have 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.

Working Capital

At December 31, 2004, our current assets of approximately $31.0 million exceeded our current liabilities of $7.0 million resulting in a working capital surplus of approximately $24.0 million. This compares to a working capital surplus of $3.9 million as of December 31, 2003. Current liabilities as of December 31, 2004 consisted of (in the following approximate amounts) trade payables of $2.5 million, $1.5 million promissory note, $2.5 million prepaid oil sales and $0.3 million advance proceeds from the sale of other assets and accrued liabilities of $0.2 million.

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Capital Expenditures

Capital expenditures in 2004, 2003 and 2002 were $11.2 million, $5.3 million and $10.7 million, respectively. The table below sets forth the components of these capital expenditures for the three years ended December 31, 2004 2003 and 2002.

	December 31,		
Expenditure category:	**2004**	**2003**	**2002**
Development	$ 6,588,137	$ 5,200,614	$ 543,280
Exploration	1,757,010	(329,998)	12,167,238
Facilities and other	2,845,143	412,772	(1,975,366)
Total	**11,190,290**	5,283,388	10,735,152

The negative expenditures recorded in Facilities and other recorded in 2002 is principally as a result of expenditures being reclassified to development and exploration expenditure from Facilities and other when actual work is performed.

During 2004, 2003 and 2002 capital expenditures were primarily for the development and exploration of existing properties. During 2002, capital expenditures were primarily related to exploration activity. We currently have a contingent planned minimum capital expenditure budget of $32 million subject to financing being available for 2005, of which all is allocated to Georgian development and appraisal projects. During 2005 and into 2006, we plan to participate in the drilling of up to fifteen horizontal sidetracks from existing wells on the Ninotsminda and Samgori Fields, complete the testing of the Manavi oil discovery well, M11, and drill at least one appraisal well on the Manavi structure. 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.

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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,		
	2004	**2003**	**2002**
Net cash generated (used in) operating activities	$ **(3,781,078)**	$ 4,430,921	$ 1,634,629
Net cash used in investing activities	**(9,967,084)**	3,228,768	(8,431,282)
Net cash provided in financing	**34,771,028**	875,325	3,174,870
Net cash flows from assets and liabilities held for sale	**121,929**	(190,227)	(683,308)
Total	**21,144,795**	1,887,252	(4,305,091)

Operating activities for the year ended December 31, 2004 used $3.8 million of cash. Investing activities used $10.0 million during 2004. Financing activities provided us $34.8 million during 2004. These funds will be used primarily to continue to fund and develop our Georgian projects. In 2004, cash used in operating activities was $3.8 million and this was used principally for production purposes on the Ninotsminda and Samgori Fields in Georgia and to fund selling, general and administrative overhead. In 2004, cash used in investing activities was due to capital expenditures principally in Georgia ($11.9 million), prepaid expenditures relating activities in Georgia ($0.5 million) and cash investment and advances in respect of our Kazakhstan Project ($0.4 million) partially offset by the proceeds from disposals of CSOP and LVR ($2.1 million).

Future Capital Resources

We will have five principal sources of liquidity going forward: (i) cash on hand, (ii) cash from operating activities, (iii) funding under the Cornell Capital Equity Facility, (iv) industry participation in our projects, and (v) sales of producing properties. We may also attempt to raise additional capital through the issuance of additional debt or equity securities in public offerings or through private placements.

Balance Sheet Changes

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

Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

Cash and cash equivalents increased $21,145,000 to $24,617,000 at December 31, 2004 from $3,472,000 at December 31, 2003. The increase was primarily due to additional net cash generated from the net proceeds received from a global public offering of 75 million shares of our common stock in September 2004; cash provided from other loan financing activities; advanced proceeds from the sale of subsidiaries; and an increase in cash generated by operating activities These funds were partially offset by expenditures in the period to fund the cost of preparing wells for our horizontal development program at the Ninotsminda and Samgori Fields in Georgia and further drilling of the Norio exploration well.

Restricted cash of $1,400,000 at December 31, 2004 relates to money placed in a third party escrow account in October 2004, to fund part of the horizontal development program at the Ninotsminda and Samgori Fields in Georgia.

Accounts receivable increased to $2,526,000 at December 31, 2004 from $162,000 at December 31, 2003 principally due to amounts recoverable from Georgian Oil Samgori Limited for their share of capital expenditure on our horizontal well drilling program at the Samgori field ($1,057,534) and amounts recoverable from our insurers ($1,047,357) in respect to a blow out of our N100 well. Our insurers will cover 80% of the costs associated with the blow out. Costs incurred as of December 31, 2004 were $1,309,198.

Crude oil inventory decreased to $254,000 at December 31, 2004 from $469,000 at December 31, 2003 primarily as result of increased sales from storage in the period. NOC held approximately 9,000 bbls of oil in storage at December 31, 2004 for sale to the Georgian domestic, regional or international markets. CSL held approximately 6,000 bbls of oil in storage at December 30, 2004 for sale to the Georgian domestic, regional or international markets.

Prepayments increased to $1,518,000 at December 31, 2004 from $962,000 at December 31, 2003 as a result of an increase in prepayments for materials and services related to our exploration activities for our horizontal well development program at the Ninotsminda and Samgori Fields and drilling of the Norio exploration well. Upon receipt of the materials and services, those amounts will be transferred to capital assets. This increase is included in the statement of cash flows as an investing activity.

Assets held for sale decreased by $9,746,000 to $600,000 at December 31, 2004 from $10,346,000 at December 31, 2003 due to the disposal of CSOP, a chain of petrol stations in Georgia. The remaining asset held for sale as at December 31, 2004 consists of a 3-megawatt duel fuel power generator.

Other current assets decreased to $122,000 at December 31, 2004 from $206,000 at December 31, 2003 primarily due to the return of deposits placed to secure professional services.

Capital assets, net increased from $57,668,000 at December 31, 2003 to $72,996,000 at December 31, 2004, primarily as a result of $3,880,000 recorded for the value of the shares of our common stock we issued to Europa Oil Services Ltd for its services in connection with our purchase of our interest in the Samgori Production Sharing Contract, a further $2,968,000 attributable to capital assets resulting from the buyout of the minority in CanArgo Norio Limited in the period; and by $11,200,000 invested in capital assets including oil and gas properties and equipment, principally related to the Ninotsminda and Samgori Production Sharing Contracts. Less $2,881,000 of Depreciation and Depletion.

Prepaid financing fees of $649,000as at December 31, 2004 represent the external costs incurred of raising future capital funds in respect of the Cornell Capital Standby Equity Distribution Agreement.

Investments in and advances to oil and gas and other ventures net, increased from $75,000 at December 31, 2003 to $478,632 at December 31, 2004 as a result of the acquisition of oil and gas interests in Kazakhstan partially offset by the impairment of our investment in our project in the Caspian Sea during the period.

Accounts payable increased from $483,000 at December 31, 2003 to $2,332,000 at December 31, 2004 primarily due to accrued liabilities in respect of preparing wells for our horizontal development program at the Ninotsminda and

Samgori Fields in Georgia.

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Advance from joint venture partner decreased from $773,000 at December 31, 2003 to nil at December 31, 2004 due to capital expenditures incurred on the MK-72 Norio well reducing the amount due to the joint venture partner, partially offset by a further receipt of funds from Georgian Oil in accordance with the Norio farm-in agreement. Of the $1,717,612 advanced at December 31, 2004 from Georgian Oil, expenditures incurred on the MK-72 well have reduced the amount due to the joint venture partner by an equal amount at December 31, 2004.

Loans payable of $1,500,000 at December 31, 2004 related to a promissory note issued to Cornell during the period. Loans payable of $102,179 at December 31, 2003 related to a short-term secured loan facility that matured on February 27, 2004. The loan was entered into by a subsidiary of CanArgo, locally in Georgia, at an annual interest rate of 20% in order to fund the drilling of the N4H horizontal well at the Ninotsminda Field in Georgia. We had provided no parent company guarantee with respect to this loan. The loan matured and was paid off in full in February 2004.

Other Liabilities decreased from $5,474,000 at December 31, 2003 to $ 3,081,000 at December 31, 2004 primarily due to the disposal of our interest in CSOP where advance proceeds received from the sale of CSOP recorded at December 31, 2003 were reclassified to gain on sale of disposition and a decrease in prepaid oil sales.

Income taxes payable of $97,500 at December 31, 2003 in relation to our subsidiary, NOC, were discharged during 2004.

Accrued liabilities decreased to $172,000 at December 31, 2004 from $349,000 at December 31, 2003 primarily due to a reduction in accrued professional fees.

Liabilities held for sale of $4,448,000 at December 31, 2003 have reduced to zero due to the disposal of CSOP.

Long term debt of $832,000 at December 31, 2004 related to a $1,050,000 convertible loan facility convertible into common stock with detachable warrants to purchase 2,000,000 common shares. In accordance with EITF 00-27 Application of Issue No. 98-5 to Certain Convertible Instruments , a portion of the proceeds of debt is accounted for as a discount to the face amount of the notes and is based on the relative fair value of the loans and the warrant securities and conversion stock at the time of issuance. At December 31, 2004 the unamortized discount amounted to $218,000.

Provision for future site restoration increased from $152,000 at December 31, 2003 to $422,000 due to the increased number of wells as a result of the Samgori acquisition.

Minority interest in continuing and discontinued subsidiaries is reduced to zero at December 31, 2004 from $4,773,000 at December 31, 2003 due to the disposal of CSOP which removed $2,897,000 of minority interest, a decrease of $1,352,000 relating to the purchase of the remaining minority interest in CanArgo Norio Limited during the period and a decrease of $524,000 in the minority interest share of income relating to GAOR resulting from the disposal of our interest in that company in the period.

Deferred compensation expense of $1,976,102 at December 31, 2004 relates to the unamortised portion of share options issued expense.

The foreign currency translation is reduced to zero at December 31, 2004 from $146,463 at December 31, 2003 due to the disposal of CSOP.

Results of Continuing Operations

Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

In April 2004, we announced that we had completed our acquisition of a 50% interest in the Samgori (Block XI^{B}) Production Sharing Contract in Georgia.

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We recorded operating revenue from continuing operations of $ 9,574,000 during the year ended December 31, 2004 compared with $ 8,105,000 for the year ended December 31, 2003. The increase is attributable to higher oil and gas revenues being recorded in the year ended December 31, 2004. NOC and CSL sold 364,319 barrels of oil for the year ended December 31, 2004 compared to 387,721 barrels of oil for the year ended December 31, 2003

NOC generated $7,833,000 of oil and gas revenue in the year ended December 31, 2004 compared with $7,881,000 for the year ended December 31, 2003 due to a higher average net sales price achieved in the year ended December 31, 2004 compared to the year ended December 31, 2003. Sales volumes remained constant over the period. Its net share of the 370,176 bbls (1,011 bopd) of gross oil production for sale from the Ninotsminda Field in the period amounted to 242,131 bbls. In the period, 71,899 bbls of oil were removed from storage and sold. A further 9,000 bbls were removed from storage and returned to Georgian Oil in recognition of agreed losses since the inception of the Production Sharing Contract. For the year ended December 31, 2003, NOC s net share of the 695,174 bbls (1,906 bopd) of gross oil production was 451,863 bbls.

CSL generated $1,742,000 of oil and gas revenue from the purchase date to December 31, 2004. Its net share of the 152,169 bbls (2,832 bopd) of gross oil production for sale from the Samgori Field in the period amounted to 57,063 bbls. As at December 31, 2004, 5,964 bbls of oil remained in storage.

NOC and CSL s entire share of production was sold locally in Georgia under both national and international contracts. Net sale prices for Ninotsminda and Samgori oil sold during 2004 averaged $26.21 per barrel as compared with an average of $20.07 per barrel in 2003. Its net share of the 65,066 thousand cubic feet (mcf) of gas delivered was 42,293 mcf at an average net sale price of $1.41 per mcf of gas. For the year ended December 31, 2003, NOC s net share of the 108,630 mcf of gas delivered was 82,156 mcf at an average net sales price of $ 1.25 per mcf of gas. No gas was produced at the Samgori Field from the acquisition date of the Production Sharing Contract to December 31, 2004.

The operating loss from continuing operations for the year ended December 31, 2004 amounted to $2,954,000 compared with an operating loss of $159,000 for the year ended December 31, 2003. The increase in operating loss is attributable a loss from the disposal of Lateral Vector Resources Inc., increased field operating costs, increased direct project costs, increased selling, general and administration costs and impairments to our Caspian project, partially offset by increased oil and gas revenue, a gain generated from the disposal of our interest in GAOR, and reduced depreciation, depletion and amortization in the period.

Field operating expenses increased to $2,321,000 ($6.33 per boe) for the year ended December 31, 2004 as compared to $1,052,000 ($2.59 per boe) for the year ended December 31, 2003. The increase is primarily a result of a decrease in production at the Ninotsminda Field during the period and the inclusion of the Samgori Field expenditures resulting from the acquisition of an interest in the Samgori (Block XIB) Production Sharing Contract (Samgori PSC) in Georgia. The reduction in production at the Ninotsminda Field was a result of us continuing to focus on the long-term development of our producing assets in Georgia through the preparation of wells for the Under Balanced Coiled Tubing Drilling (UBCTD) development program. This necessitated the shut in of producing wells during the period thus resulting in a lower average production for the period. We have not had a corresponding decrease in our operating cost as the majority of our operating costs are fixed.

Direct project costs increased to $1,434,000 for the year ended December 31, 2004, from $1,029,000 for the year ended December 31, 2003, primarily due to costs directly associated with non operating activity at the Ninotsminda Field and the inclusion of Samgori project cost expenditures following our acquisition of an interest in the Samgori PSC in Georgia.

Selling, general and administrative costs increased to $5,929,000 for the year ended December 31, 2004, from $3,229,000 for the year ended December 31, 2003. The increase is primarily as a result of additional internal costs incurred in respect of fund raising activities relating to the recent public global offering & increased corporate activity over 2003.

Non cash stock compensation of $277,000 for the year ended December 31, 2003 relates to the Company, effective January 1, 2003, adopting in August 2003, the fair value recognition provisions of SFAS No. 123, *Accounting for*

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Stock-Based Compensation prospectively to all employee awards granted, modified, or settled after December 31, 2002. Non cash stock compensation of $1,395,000 for the year ended December 31, 2004 relates to additional employee awards granted in the period. During the year ending December 31, 2004 we issued 6,298,000 stock options to directors and employees. On August 24, 2004, 5,688,000 of these options were issued, all with a two year vesting period from issue date of the option. The remaining 610,000 stock options were issued over various dates and have varying vesting terms ranging from immediate to two years. We recorded $3,371,000 of deferred compensation expense as a separate component of equity in respect of these options.

The decrease in depreciation, depletion and amortization expense to $2,881,000 for the year ended December 31, 2004 from $3,294,000 for the year ended December 31, 2003 is attributable principally to reductions in production during 2004 as compared to 2003 and from inclusion of the depletion of estimated reserves at the Samgori Field which had the effect of diluting the depletion rate per barrel and reduced overall depletion for the year ended December 31, 2004. We have not yet obtained an independent assessment of proved reserves for the Samgori Field.

We impaired our Caspian Sea project to zero during the year ended December 31, 2004 with a write down of $65,000 of oil and gas properties and a $75,000 write down of our investment.

Impairment of other assets of $35,000 during the year ended December 31, 2004 relates to repairs to the held for sale generator which are not recoverable.

During 2003, we also announced we had reached conditional agreement to sell our interest in Boryslaw Oil Company, the joint venture in West Ukraine currently operating the Stynawske Oil Field. Fountain Oil Boryslaw, our wholly owned subsidiary which holds our 45% interest in Boryslaw Oil Company, was sold for $1,000,000 and a gain on disposal of $665,000 was also recorded in gain on disposition of investments during the period.

The gain on disposal of subsidiaries of $1,607,000 recorded for the year ended December 31, 2004 reflects gains from the disposals of CSOP and of our interest in GAOR.

We recorded net other expense of $2,345,000 for the year ended December 31, 2004, as compared to $605,000 for the year ended December 31, 2003. The increase in net other expense of $1,740,000 is primarily due to an increase in interest expense of $647,000 largely resulting from the amortization of the discount on debt issued with detachable stock purchase warrants and on convertible debt incurred during the period in accordance with APB 14 and EITF 00-27; additional other expenses relating to an extinguished loan of $350,000, foreign exchange losses, and, equity income from investments.

Equity loss from investments for the year ended December 31, 2003 of $ 205,000 relates to the loss incurred on the project in Kazakhstan to acquire oil and gas properties. The equity income for the year ended December 31, 2003 of $66,000 is from the production and sales of crude oil by Boryslaw Oil Company, subsequently disposed of in the fourth quarter of 2003.

The cumulative effect of the change in accounting principle of $41,000 for the year ended December 31, 2003 was a result of the adoption of accounting standard FAS 143 relating to the treatment of asset retirement obligations.

The loss from continuing operations of $5,300,000 or $0.04 per share for the year ended December 31, 2004 compares to a net loss from continuing operations of $756,000 or $0.01 per share for the year ended December 31, 2003. The weighted average number of common shares outstanding was higher during the year ended December 31, 2004 than during the year ended December 31, 2003, principally due to share issues in respect of the Manavi agreements in fourth quarters of 2003 and the issue of shares in respect of the Samgori purchase in April 2004, the exercise of share options in 2004, the issue of shares in respect of a global offering in September 2004 and the issue of shares in respect of the Norio minority interest buyout in September 2004.

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

We recorded operating revenue of $8,105,000 during the year ended December 31, 2003 compared with $5,486,000 for the year ended December 31, 2002. The increase is primarily attributable to higher oil and gas revenues, being partially offset by lower other revenue being recorded in the twelve month period ended December 31, 2003. Other revenue for the twelve month period ended December 31, 2003 and 2002 represented the provision of drilling services in Georgia.

NOC generated $7,881,000 of oil and gas revenue in the year ended December 31, 2003 compared with $4,163,000 for the year ended December 31, 2002 due to higher volume of sales resulting from increased production from the successful horizontal wells completed in 2003 and a higher average net sales price achieved in 2003. Its net share of the 695,174 bbls (273 bopd) of gross oil production for sale from the Ninotsminda Field in the period amounted to 451,863 bbls. In 2003, 64,142 bbls of oil were added to storage**.** For the year ended December 31, 2002, NOC s net share of the 292,289 barrels (801 bopd) of gross oil production was 189,988 bbls. The increase in production is due to the successful horizontal development wells completed at the Ninotsminda Field in 2003.

NOC s entire share of production was sold locally in Georgia under both national and international contracts. Net sale prices for Ninotsminda oil sold during 2003 averaged $20.07 per barrel as compared with an average of $17.09 per barrel in 2002. Its net share of the 108,630 thousand cubic feet (mcf) of gas delivered was 82,156 mcf at an average net sale price of $1.25 per mcf of gas. For the year ended December 31, 2002, NOC s net share of the 212,499 mcf of gas delivered was 138,124 mcf at an average net sales price of $1.25 per mcf of gas.

We had other revenue of $224,000 for the year ended December 31, 2003 compared to other revenue of $1,323,000 for the year ended December 31, 2002. In 2003 and 2002, other revenue consisted of the provision of drilling services. In September 2001, we entered into an agreement to provide drilling services to a third party using one of our rigs. Commercial drilling operations commenced in October 2001 and continued through February 2002. We subsequently established a wholly owned well services subsidiary (Argonaut Well services Limited) and at the end of March 2003 concluded a new drilling services contract with an operating company in Georgia. It will continue to bid in appropriate tenders for drilling contracts in order to utilize drilling equipment not otherwise used in its own operations.

The operating loss from continuing operations for the year ended December 31, 2003 amounted to $159,000 compared with an operating loss of $4,902,000 for 2002. The decrease in operating loss is attributable primarily to a reduction in field operating expenses, reduced selling, general and administration expense, reduced direct project costs in the period, and an impairment of oil and gas properties in 2002; partially offset by an increase in depletion and amortization in the period; and stock compensation in expense in 2003.

Field operating expenses decreased to $1,052,000 ($2.59 per boe) for the year ended December 31, 2003 as compared to $1,538,000 ($4.69 per boe) for 2002. The decrease is primarily a result of a cost reduction program initiated in the last quarter of 2002 at the Ninotsminda Field and costs relating to increase of oil storage in the year. Operating costs per boe decreased as day-to-day field operations in Georgia include a proportionately higher fixed to variable cost component combined with a cost reduction program initiated in the last quarter of 2002 at the Ninotsminda Field and higher production rates.

Direct project costs decreased to $1,029,000 for the year ended December 31, 2003, from $1,429,000 for the year ended December 31, 2002, primarily due to costs associated with the provision of drilling services in Georgia in 2002.

Selling, general and administrative costs decreased to $3,229,000 for the year ended December 31, 2003, from $3,494,000 for the year ended December 31, 2002. The decrease is primarily as a result of a corporate cost reduction program initiated in the last quarter of 2002.

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Non cash stock compensation expense increased to approximately $277,000 for the year ended December 31, 2003, from nil for the year ended December 31, 2002 due to the Company, effective January 1, 2003, adopting the fair value recognition provisions of SFAS No. 123, Accounting for Stock-Based Compensation, prospectively to all employee awards granted, modified, or settled after December 31, 2002.

The increase in depreciation, depletion and amortization expense to $3,294,000 for the year ended December 31, 2003 from $2,317,000 for the year ended December 31, 2002 is attributable principally to higher production resulting from the successful horizontal wells at the Ninotsminda Field completed in 2003.

We wrote down our oil and gas properties in the Ninotsminda Field by an aggregate $1,600,000 on application of the full cost ceiling test as a result of lower reserve quantities following production declines in 2002. The write-down was a non-cash write-down. If oil prices or production levels declined in the future, we may experience an additional impairment of this property.

During 2003, we also announced we had reached conditional agreement to sell our interest in Boryslaw Oil Company, the joint venture in West Ukraine currently operating the Stynawske Oil Field. Fountain Oil Boryslaw, our wholly owned subsidiary which holds our 45% interest in Boryslaw Oil Company, was sold for $1,000,000 and a gain on disposal of $665,000 was also recorded in gain on disposition of investments during the period.

We recorded net other expenses of $605,000 for the year ended December 31, 2003, as compared to net other expense of $576,000 during the year ended December 31, 2002. The increase is primarily due to foreign exchange translation losses during 2003 partially offset by our adjusted interest in its share of the carrying net asset value of our subsidiary CanArgo Norio Limited (Norio) giving rise to a non-operating loss of $444,000, in accordance with the application of SAB 51, following agreement with the minority shareholders on the finalization of respective equity interest in Norio in 2002, and a bad debt allowance of $275,000 being recorded in 2002.

Equity income from investments decreased to $66,000 for the year ended December 31, 2003 from an equity income of $86,000 for the year ended December 31, 2002 primarily as a result of only nine months of equity income recorded from production and sales of crude oil by Boryslaw Oil Company prior to its disposal in the last quarter of 2003.

The net loss from continuing operations of $756,000 or $0.01 per share for the year ended December 31, 2003 compares to a net loss from continuing operations of $5,478,000 or $0.06 per share for the year ended December 31, 2002. The weighted average number of common shares outstanding was higher during the year ended December 31, 2003 than during the year ended December 31, 2002, due in large part to share issues in respect of agreements relating to of Norio and Manavi projects during 2003.

The cumulative effect of change in accounting principle of $41,290 at December 31, 2003 relates to the adoption of FASB Statement No. 143 Accounting for Asset Retirement Obligations (SFAS 143) on January 1, 2003. SFAS 143 requires companies to record the discounted fair value of a liability for an asset retirement obligation in the period in which the liability is incurred concurrent with an increase in the long-lived assets carrying value. The increase and subsequent adjustments in the related long-lived assets carrying value is amortised over its useful life. Upon settlement of the liability a gain or loss is recorded for the difference between the settled liability and the recorded amount. The discount associated with the liability is accreted into income over the related asset s useful life. Upon adoption of this standard an entity is required to record the fair value of its existing asset retirement obligations as if the liabilities had been initially accounted for in accordance with SFAS 143 using assumptions present at the date of adoption. The income statement effect of the treatment is recorded as a cumulative effect in accounting principle in the period of adoption, no retroactive restatement is permitted.

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Results of Discontinued Operations

Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

The net income from discontinued operations, net of taxes and minority interest for the year ended December 31, 2004 amounted to $542,210 compared with net loss of $6,607,517 for the corresponding period in 2003. The increase in net income from discontinued operations, net of taxes and minority interest relates to the losses resulting from the activities of Lateral Vector Resources Inc. (LVR) and GAOR in 2003, offset partially by income relating to the refinery resulting from the disposal of the refinery in the period and income from CSOP during the period.

In September 2002, we approved a plan to sell our interest in 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.

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.

Lateral Vector Resources Inc. (LVR), a wholly-owned 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, 2005, we had not received any further payments.

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

The net income from discontinued operations, net of taxes and minority interest for the year ended December 31, 2003 amounted to $6,608,000 compared with net income of $150,000 for the corresponding period in 2002. The increase in net loss from discontinued operations, net of taxes and minority interest relates to the activities of LVR and GAOR, offset partially by the activities of CSOP. Losses increased at GAOR as there was no income in the year ended December 31, 2003.

During 2003**,** CanArgo approved a plan to sell its interest in the Bugruvativske Field and recorded a write-down of $4,790,727 in 2003 of unproved oil and gas properties to reflect the estimated recoverable amount from disposal**.**

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An impairment of other assets of $1,355,000 for the year ended December 31, 2003, from nil for the year ended December 31, 2002 was due to a write-down of the minority interest share of losses relating to GAOR of $1,274,895 and the a write- down of a generator in the period to its net realizable value by $80,000. During 2003, a debit balance of $1,274,895 in minority interest was written-off due to a change in the intentions of our minority interest owner and a plan to dispose of the asset. In 2004, CanArgo came to an agreement to sell the refinery.

Increased income at CSOP is due to higher sales volume during 2003 offset partially by more competitive operating margins for the year ended December 31, 2003 compared with the corresponding period in 2002. Increased income at LVR related to foreign exchange gains in the period for the year ended December 31, 2003 compared with the corresponding period in 2002

Contractual Obligations and Commercial Terms

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

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

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

- The State of Georgia recognizes and confirms the validity and enforceability of the production sharing contract and the license and all undertakings the State has covenanted with NOC thereunder;
- the license was duly authorized and executed by the State at the time of its issuance and remained in full force and effect throughout its term; and
- the license constitutes a valid and duly authorized grant by the State, being and remaining in full force and effect as of the signing of this confirmation and the benefits of the license fully extend to NOC by virtue of its interest in the license holder and the contractual rights under the production sharing contract.

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

In 2002, the Participation Agreement for the three well exploration program on the Ninotsminda / Manavi area with AES was terminated without AES earning any rights to any of the Ninotsminda / Manavi area reservoirs. The Company therefore has no present obligations in respect of AES. However, under a separate Letter of Agreement, if gas from the sub Middle Eocene is discovered and produced from the exploration area covered by the Participation Agreement, AES with be entitled to recover at the rate of 15% of future gas sales from the sub Middle Eocene, net of operating costs, approximately $7,500,000, representing their prior funding under the Participation Agreement.

Under the Production Sharing Contract for Blocks XI^G and XI^H (the Tbilisi PSC) in the Republic of Georgia our subsidiary CanArgo Norio Limited 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 Agreement which is September 29, 2003. The total commitment over the next two years is $350,000.

In April 2004, we acquired a 50% interest in the Samgori (Block XI^{B}) Production Sharing Contract (Samgori PSC) in Georgia. This interest was acquired from GOSL, a company wholly owned by Georgian Oil, by one of our subsidiaries, CSL. Under the terms of the agreement dated January 8, 2004, up to 10 horizontal wells will be drilled on the Samgori Field. Completion of well S302, which was funded 100% by us satisfied our commitment to GOSL under the acquisition agreement, the remainder of the drilling program will 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 is due to be completed within 36 months of the work commencement date (WCD), (which is expected to begin within the next two months), is anticipated to be up to $13,500,000.

The original Contractor party to the Samgori PSC, NPL, has 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 is not completed in part within 18 months of the WCD and in full within 36 months of the WCD. Furthermore, 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). The Cost Recovery pool includes the $37,528,964 costs previously incurred by NPL. The balance of production (Profit Oil) is allocated on a 60/40 basis between the State and the Contractor parties respectively. While GOSL and CSL continue to have unrecovered costs, they will receive 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 will receive 30% of Profit Oil (net 15% to us). The allocation of a share of production to the State, however, relieves the Contractor parties of all obligations they would otherwise have to pay the Republic of Georgia for taxes, duties and levies related to activities covered by the Samgori PSC. After NPL s costs are 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 shall 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.

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

Upon completion of the acquisition of an interest in the Samgori PSC we had a contractual obligation to issue four million shares of CanArgo Common Stock to Europa Oil Services Limited (Europa), an unaffiliated company in connection with a consultancy agreement with Europa in relation to this acquisition. On April 16, 2004 Europa was issued with four million restricted shares of CanArgo Common Stock in an arms length transaction. A further 12 million shares of CanArgo Common Stock are issuable upon certain production targets being met from future developments under the Samgori PSC.

At December 31, 2004, we had a contingent obligation to issue 187,500 shares of common stock to Fielden Management Services PTY, Ltd (a third party management services company) upon satisfaction of conditions relating to the achievement of specified Stynawske Field project performance standards, an oil field in Ukraine in which we had a previous interest.

If Georgian Oil exercises the option available to it under the terms of the Norio farm-in agreement signed in September 2003, and pays $6,500,000 to us, we would issue a further 3 million restricted shares to the minority interest holders, Provincial Securities Limited and GBOSC, from whom we acquired an additional 10.8% interest in CanArgo Norio Limited.

In September 2004, we had a blow out of our N100 well on our Ninotsminda Field which was successfully capped three days later. We estimate that the total costs attributable to the blow out, including compensation and cleaning of the environment will be $1,527,000. The Company insurance policies covered 80% of these costs, the other 20% insurance retention being payable by us. We have accrued liabilities of $315,000 to cover these costs.

The following table sets forth information concerning the amounts of payments due under specified contractual obligations for periods of less than one year, one to three years, three to five years and more than five years as at December 31, 2004

Contractual Obligations	**Due in less than 1 year**	**Due in 1 to 3 years**	**Due in 3 to 5 years**	**Due in more than 5 years**
Operating lease obligations	$ 363,550	634,000	625,260	156,315
Loans payable	1,500,000			
Long term debt		1,050,000		
Other long-term liabilities (1)				422,000
	$ 1,863,550	**1,684,000**	**625,260**	**578,315**

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

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

Related Party Transactions

A company owned by significant employees of Georgian British Oil Company Ninotsminda provides certain equipment to Georgian British Oil Company Ninotsminda. Total rental payments for this equipment in 2004 were $107,946 ($183,428 in 2003). In 2004, the same company provided additional services to Georgian British Oil Company Ninotsminda in accordance with the farm-in agreement in respect of the Manavi well for the value of $450,000.

Dr. David Robson, Chief Executive Officer, provides all of his services to CanArgo through Vazon Energy Limited of which he is the Managing Director.

Mr. Russell Hammond, a non-executive director of CanArgo, is also an Investment Advisor to Provincial Securities Limited who became a minority shareholder in the Norio and North Kumisi Production Sharing Agreement through a farm-in agreement to the Norio MK72 well. On September 4, 2003 we concluded a deal to purchase Provincial Securities Limited s minority interest in CanArgo Norio Limited by a share swap for shares in CanArgo. Provincial Securities Limited received 2,234,719 shares of CanArgo common stock in relation to the transaction. Provincial Securities Limited also has an interest in Tethys Petroleum Investments Limited, a company in which CanArgo holds a 45% interest. Transactions with affiliates or other related parties including management of affiliates are to be undertaken on the same basis as third party arms-length transactions. Transactions with affiliates are reviewed and voted on solely by the audit committee.

Transactions with affiliates are reviewed and voted on solely by non-interested directors.

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Critical Accounting Policies

Natural Gas and Oil Properties

We utilize the full cost method of accounting for costs related to our natural gas and oil properties. We review the carrying value of our natural gas and oil properties under the full cost accounting rules of the SEC. Under these rules, all such costs (productive and non-productive) are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test, however, which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved gas and oil reserves discounted at 10 percent plus the lower of cost or market value of unproved properties. If the net capitalized costs of natural gas and oil properties exceed the ceiling, we will record a ceiling test write-down to the extent of such excess. A ceiling test write-down is a non-cash charge to earnings. If required, it reduces earnings and impacts shareholders equity in the period of occurrence and results in lower depreciation, depletion and amortization expense in future periods. The write-down may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling.

The risk that we will be required to write-down the carrying value of our natural gas and oil properties increases when natural gas and oil prices are depressed or if there are substantial downward revisions in estimated proved reserves. Application of these rules during periods of relatively low natural gas or oil prices due to seasonality or other reasons, even if temporary, increases the probability of a ceiling test write-down. Based on natural gas and oil prices in effect on December 31, 2004, the unamortized cost of our natural gas and oil properties did not exceed the ceiling of proved natural gas and oil reserves. Natural gas pricing has historically been unpredictable and any significant declines could result in a ceiling test write-down in subsequent quarterly or annual reporting periods.

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

Use of Estimates in the Preparation of Financial Statements

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

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

Concentration of Credit Risk

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

Foreign Operations

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

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New Accounting Standards

In September 2004, the Securities and Exchange Commission issued Staff Accounting Bulletin (SAB) No. 106 which expressed the Staff s views regarding the application of Statement of Financial Accounting Standards (SFAS) No. 143 Accounting for Asset Retirement Obligations by oil and gas producing companies following the full-cost accounting method. SAB No. 106 specifies that subsequent to the adoption of SFAS No. 143 an oil and gas company following the full-cost method of accounting should include assets recorded in connection with the recognition of an asset retirement obligation pursuant to SFAS No. 143 as part of the costs subject to the full-cost ceiling limitation. The future cash outflows associated with settling the recorded asset retirement obligations should be excluded from the computation of the present value of estimated future net revenues used in applying the ceiling test. The Company will be required to adopt the provisions of SAB No. 106 prospectively in the first quarter of 2005 which will have no impact on the Company s results of operation or financial position.

In September 2004, the FASB issued a FASB Staff Position to clarify that the scope exception in paragraph 8(b) of SFAS No. 142 includes the balance sheet classification and disclosures for drilling and mineral rights of oil and gas producing companies. Therefore, our historical practice of including the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties under SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, has been affirmed by the new FSP.

Forward-Looking Statements

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

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

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

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

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

- world economic conditions;

- the state international relations;

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

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

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

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Also as indicated elsewhere in this Report, because all of our operations are being conducted in the former Soviet Union, we are potentially exposed to the market risk of fluctuations in the relative values of the currencies in areas in which we operate. At present we do not engage in any currency hedging operations since, to the extent we receive payments for our production and marketing activities in local currencies, we are utilizing such currencies to pay for our local operations. In addition, our contracts to sell our production from the Ninotsminda and Samgori Fields in the Republic of Georgia are denominated in U. S.dollars with all export contracts providing for payment in dollars, although we may not always be able to continue to demand payment in U.S. dollars.

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

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

Assuming the same production in 2005 as 2004 but decreasing the net oil price we receive from sales by $5.00 and $10.00 respectively would change the total annual revenue from oil sales as follows. The total annual revenue from oil sales for 2004 based on an average net oil price received of $26.15 was $9,574,520. If the average net oil price received was $5.00 less at $21.15 then the total annual revenue from oil sales would be reduced by $1,794,588 to $7,591,106. If the average net oil price received was reduced by $10 per barrel then the total annual revenue from oil sales realised would be reduced by $3,589,175 to $5,796,518, assuming all other factors are constant.

Assuming constant oil prices but a reduction in annual production by 20% and 50% would have the following effect on total annual revenues. In 2004 the total oil sales were 358,917 bbls of oil producing revenue of $9,574,520. If this was reduced by 20% then the annual revenue from oil sales would be reduced to $7,508,555. If the total annual oil sales were reduced by 50% or 179,456 bbls then the total annual revenue from oil sales would be $4,692,847. Assuming all other factors are constant.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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

As noted in the Form 8-K filed in July 2003, our Board of Directors engaged the accounting firm of L.J. Soldinger Associates LLP as our certifying accountant for the year ended December 31, 2003. The engagement of L J Soldinger Associates LLC was approved by the Audit Committee of the Board of Directors. The reports of PricewaterhouseCoopers LLP (PwC) on the Company s financial statements for the fiscal year ended December 31, 2002 did not contain any adverse opinion or disclaimer of opinion and were not qualified or modified as to uncertainty, audit scope or accounting principles but PwC s report on the financial statements for the fiscal year ended December 31, 2002 did contain an explanatory paragraph for an uncertainty regarding the Company s ability to continue as a going concern. In connection with the audits of the Company s financial statements for the fiscal years ended December 31, 2002, there were no disagreements with PricewaterhouseCoopers LLP on any matters of accounting principles, financial statement disclosure or audit scope and procedures which, if not resolved to the satisfaction of PricewaterhouseCoopers LLP, would have caused the firm to make reference to the matter in their report.

ITEM 9A. CONTROLS AND PROCEDURES

Management s Responsibility for Financial Statements

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

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Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to the officers who certify the Company s financial reports and to other members of senior management and the Board of Directors. Based on their evaluation as of December 31, 2004, our Chief Executive Officer and Chief Financial Officer have concluded that the Company s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) are effective to ensure that the information required to be disclosed by the Company in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms.

Management s Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in the rules promulgated under the Securities Exchange Act of 1934. Under the supervision and with the participation of our management, including our principal executive, financial and accounting officers, we are still in the process of conducting an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. We intend to file an amendment to this Annual Report with the SEC upon completion of our evaluation which will contain a management report describing the results of our evaluation.

As a result of our efforts in 2004 to comply with Section 404 of the Sarbanes-Oxley Act of 2002 and the rules issued thereunder, we reported in our Form 10-Q for the third fiscal quarter of 2004 that we had identified certain deficiencies that exist in the design and operation of our internal controls that L J Soldinger Associates, LLC, our independent registered auditors, considers to be material weaknesses in the effectiveness of our internal controls pursuant to the standards established by the American Institute of Certified Public Accountants., which individually or in the aggregate could constitute material weaknesses in the design or operation of internal control over financial reporting. These deficiencies could have a material adverse effect on our ability to record, process, summarise and report financial data in the financial statements in a timely manner and as such required either remediation or the identification of alternative controls. As a result we began remediation efforts in the fourth quarter of 2004, which are still continuing as we complete our evaluation of our internal control over financial reporting.

Management retained the firm of Ernst & Young LLP in the fourth quarter of 2004 to assist it, with regard to its Georgian subsidiaries, in documenting, testing and revising its processes and controls. Management retained the firm of Ernst & Young LLP in the first quarter of 2005 to assist it, with regard to its headquarters, in documenting, testing and revising its processes and controls. Management anticipates that as a result of the evaluation that is currently ongoing, we will be able to report on the effectiveness of our internal control over financial reporting as of the date we file our amended Form 10-K. Other than as a result of this evaluation, our remediation efforts and identification of alternative controls, which began in the fourth quarter of 2004 and are continuing, there have been no changes in our internal control over financial reporting or in other factors that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER

None

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PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required by this Item is hereby incorporated by reference from our definitive proxy statement to be mailed to stockholders in connection with our 2005 annual meeting of stockholders and filed with the SEC within 120 days after the close of our fiscal year.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is hereby incorporated by reference from our definitive proxy statement to be mailed to stockholders in connection with our 2005 annual meeting of stockholders and filed with the SEC within 120 days after the close of our fiscal year.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by this Item is hereby incorporated by reference from our definitive proxy statement to be mailed to stockholders in connection with our 2005 annual meeting of stockholders and filed with the SEC within 120 days after the close of our fiscal year.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by this Item is hereby incorporated by reference from our definitive proxy statement to be mailed to stockholders in connection with our 2005 annual meeting of stockholders and filed with the SEC within 120 days after the close of our fiscal year.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item is hereby incorporated by reference from our definitive proxy statement to be mailed to stockholders in connection with our 2005 annual meeting of stockholders and filed with the SEC within 120 days after the close of our fiscal year.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) Financial Statements

The following financial statements and related notes of the Company contained on pages F-1 through F- 44 are filed as part of this Report:

Reports of Independent Auditors

Consolidated Statements of Operations and Comprehensive Loss   Years Ended December 31, 2004, 2003, and 2002.

Consolidated Balance Sheets   December 31, 2004 and 2003.

Consolidated Statements of Cash Flows   Years Ended December 31, 2004, 2003, and 2002.

Consolidated Statements of Stockholders Equity   Years ended December 31, 2004, 2003 and 2002.

Notes to Consolidated Financial Statements

(2) Financial Statements Schedules

None

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

(b) Exhibits

Management Contracts, Compensation Plans and Arrangements are identified by an asterisk (*)
Documents filed herewith are identified by a cross ( ).

1(1)	Engagement Agreement with Sundal Collier & Co ASA dated August 13, 2001. (Incorporated herein by reference from Post-Effective Amendment No. 2 to Form S-1 Registration Statement, File No. 333-85116 filed on September 10, 2002).
1(2)	Standby Equity Distribution Agreement between Cornell Capital Partners, L.P. and CanArgo Energy Corporation dated February 11, 2004 (Incorporated herein by reference from Form S-3 filed May 6, 2003 (Reg. No. 333-115261)).
1(3)	Placement Agent Agreement between CanArgo Energy Corporation, Newbridge Securities Corporation and Cornell Capital Partners, L.P. dated February 11, 2004 (Incorporated herein by reference from Form S-3 filed May 6, 2003 (Reg. No. 333-115261)).
1(4)	Placement Agent Agreement dated September 22, 2004 by and between ABG Sundal Collier Norge ASA and CanArgo Energy Corporation (Incorporated herein by reference from Amendment No. 2 to Registration Statement on Form S-3 filed August 31, 2004 (Reg. No. 333-115645)).

1(5)	Placement Agent Agreement dated September 22, 2004 by and between ABG Sundal Collier Inc. and CanArgo Energy Corporation (Incorporated herein by reference from Amendment No. 1 to Registration Statement on Form S-3 filed July 1, 2004 (Reg. No. 333-115645)).

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1(6)	Engagement letter between ABG Sundal Collier Norge ASA and CanArgo Energy Corporation dated March 23, 2004 (Incorporated herein by reference from September 30, 2004 Form 10-Q)
2(4)	Memorandum of Agreement between Fielden Management Services Pty, Ltd., A.C.N. 005 506 123 and Fountain Oil Incorporated dated May 16, 1995 (Incorporated herein by reference from December 31, 1997 Form 10-K/A).
3(1)	Registrant s Certificate of Incorporation and amendments thereto (Incorporated herein by reference from July 15, 1998 Form 8-K).
3(2)	Registrant s Bylaws (Incorporated herein by reference from Post-Effective Amendment No. 1 to Form S-1 Registration Statement, File No. 333-72295 filed on July 29, 1999).
*4(1)	Amended and Restated 1995 Long-Term Incentive Plan (Incorporated herein by reference from Post-Effective Amendment No. 1 to Form S-1 Registration Statement, File No. 333-72295 filed on July 29, 1999).
*4(2)	Amended and Restated CanArgo Energy Inc. Stock Option Plan (Incorporated herein by reference from September 30, 1998 Form 10-Q).
4(3)	Registration Rights Agreement between CanArgo Energy Corporation and Cornell Capital Partners, L.P. dated February 11, 2004 (Incorporated herein by reference from Form S-3 filed May 6, 2003 (Reg. No. 333-115261)).
4(4)	Escrow Agreement among CanArgo Energy Corporation, Cornell Capital Partners, L.P. and Butler Gonzalez LLP dated February 11, 2004 (Incorporated herein by reference from Form S-3 filed May 6, 2003 (Reg. No. 333-115261)).
*4(5)	CanArgo Energy Corporation 2004 Long Term Stock Incentive Plan (Incorporated herein by reference from Form 8-K dated May 19 2004).
4(6)	Amended and Restated Loan and Warrant Agreement between CanArgo Energy Corporation and Salahi Ozturk dated August 27, 2004 (Incorporated herein by reference from Form 8-L dated August 16, 2004).
10(1)	Production Sharing Contract between (1) Georgia and (2) Georgian Oil and JKX Ninotsminda Ltd. dated February 12, 1996 (Incorporated herein by reference from Form S-1 Registration Statement, File No. 333-72295 filed on September 7, 1999).
*10(2)	Management Services Agreement between CanArgo Energy Corporation and Vazon Energy Limited concerning the provision of services by Dr. David Robson dated June 29, 2000 (Incorporated herein by reference from September 30, 2000 Form 10-Q). As amended by Deed of Variation of Management Services Agreement between CanArgo Energy Corporation and Vazon Energy Limited dated May 2, 2003. (Incorporated herein by reference to Form 8-K dated May 13, 2003, File No. 000-09147).
10(3)	Tenancy Agreement between CanArgo Services (UK) Limited and Grosvenor West End Properties dated September 8, 2000 (Incorporated herein by reference from September 30, 2000 Form 10-Q).

10(4)	Production Sharing Contract between (1) Georgia and (2) Georgian Oil and CanArgo Norio Limited dated December 12, 2000 (Incorporated herein by reference from December 31, 2000 Form 10-K).
*10(5)	Service Agreement between CanArgo Energy Corporation and Vincent McDonnell dated December 1, 2000 (Incorporated herein by reference from December 31, 2001 Form 10-K).
10(6)	Sale agreement of CanArgo Petroleum Products Limited between CanArgo Limited and Westrade Alliance LLC dated October 14, 2002. (Incorporated herein by reference from September 30, 2002 Form 10-Q).
10(7)	Farm-in Agreement dated September 4, 2003 relating to the Norio (Block XI^{C}) and North Kumisi Production Sharing Agreement in the Republic of Georgia with a wholly owned subsidiary of Georgian Oil, the Georgian State Oil Company (Incorporated herein by reference from September 30, 2003 Form 10-Q).

10(8)	Stock Purchase Agreement dated September 24, 2003 regarding the sale of all of the issued and outstanding stock of Fountain Oil Boryslaw (Incorporated herein by reference from September 30, 2003 Form 10-Q).
10(9)	Manavi Termination Agreement dated December 5, 2003 (Incorporated by reference from December 31, 2003 Form 10-Q).
10(10)	Termination Agreement between CanArgo Energy Corporation and Cornell Capital Partners, L.P. dated February 11, 2004 (Incorporated herein by reference from Form S-3 filed May 6, 2003 (Reg. No. 333-115261)).
10(11)	Agreement between CanArgo Samgori Limited and Georgian Oil Samgori Limited dated January 8, 2004 (Incorporated herein by reference from Form S-3 filed May 6, 2003 (Reg. No. 333-115261)).
10(12)	Consultancy Agreement between CanArgo Energy Corporation and Europa Oil Services Limited dated January 8, 2004 (Incorporated herein by reference from Form S-3 filed May 6, 2003 (Reg. No. 333-115261)).
10(13)	Loan Agreement between CanArgo Energy Corporation and Salahi Ozturk dated April 26, 2004 (Incorporated herein by reference from March 31, 2004 Form 10-Q).
10(14)	Loan Agreement between CanArgo Energy Corporation and C A Fiduciary Services Limited AS dated April 29, 2004 (Incorporated herein by reference from March 31, 2004 Form 10-Q).
10(15)	Oil Sales Agreement between CanArgo Energy Corporation and Primrose Financial Group dated May 5, 2004 (Incorporated herein by reference from March 31, 2004 Form 10-Q).
10(16)	Oil Sales Agreement between CanArgo Energy Corporation and Sveti Limited dated April 1, 2004 (Incorporated hereunder by reference from March 31, 2004 Form 10-Q).
10(17)	Agreement dated April 25, 2004 between NOC, Sveti Limited and Primrose Financial Group on the termination of the Crude Oil Sales Agreement dated April 1, 2004 between NOC and Sveti Limited and the terms for the conclusion of a new crude oil sales agreement between NOC and Primrose Financial Group (Incorporated herein by reference from March 31, 2004 Form 10-Q).
10(18)	Promissory Note dated May 19, 2004 between CanArgo Energy Corporation and Cornell Capital Partners, LP (Incorporated herein by reference from Form 8-K dated May 19, 2004) as amended by Letter of Amendment between Cornell Capital Partners, LP and CanArgo Energy Corporation dated December 21, 2004 (Incorporated herein by reference from Form 8-K dated December 21, 2004).

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10(19)	Agreement dated March 17, 2004 between CanArgo Acquisition Corporation and Stanhope Solutions Ltd for the sale of Lateral Vector Resources Ltd. (Incorporated herein by reference from Form 8-K dated May 19, 2004).
10(20)	Master Service Contract dated June 1, 2004 between CanArgo Energy Corporation and WEUS Holding Inc (Incorporated herein by reference from Form 8-K dated June 1, 2004).
10(21)	Agreement number GN-070/RIG/NOC dated June 21, 2004 between NOC and Great Wall Drilling Company Limited (Incorporated herein by reference from Form 8-K dated June 21, 2004).
10(22)	Agreement between NOC and Saipem S.p.A. dated January 27, 2005 (Incorporated herein by reference from Form 8-K dated January 27, 2005).
10(23)	Agreement between NOC and Primrose Financial Group dated February 4, 2004 (Incorporated herein by reference from Form 8-K dated February 4, 2005)
10(24)	Termination Agreement between NOC and Primrose Financial Group dated February 4, 2005 (Incorporated herein by reference from Form 8-K dated February 4, 2005).
14	Code of Ethics
21	List of Subsidiaries (Incorporated herein by reference from September 30, 2001 Form 10-Q)
23(a)	Consent of L.J. Soldinger & Associates, LLC, Independent Public Accountants.
23(b)	Consent of PricewaterhouseCoopers LLP, Independent Public Accountants.
23(c)	Consent of Oilfield Production Consultants (OPC) Limited, Independent Petroleum Consultants.
31(1)	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer of CanArgo Energy Corporation.
31(2)	Rule 13a-14(c)/15d-14(a) Certification of Chief Financial Officer of CanArgo Energy Corporation.
32	Section 1350 Certifications.

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SIGNATURES

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

CanArgo Energy Corporation
(Registrant)

By:	/s/ Vincent McDonnell	Date: March 15, 2005
	Chief Financial Officer	

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

By:	/s/ David Robson	Date: March 15, 2005
	David Robson, Chairman of the Board , President, Chief Executive Officer and Director Principal Executive Officer	
By:	/s/Vincent McDonnell	Date: March 15 2005
	Vincent McDonnell, Chief Financial Officer and Director Principal Accounting Officer	
By:	/s/Michael Ayre	Date: March 15 2005
	Michael Ayre, Director	
By:	/s/Russell Hammond	Date: March 15 2005
	Russell Hammond, Director	
By:	/s/Nils N. Trulsvik	Date: March 15 2005
	Nils N. Trulsvik, Director	

CANARGO ENERGY CORPORATION

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REPORT ON MANAGEMENT S RESPONSIBILITIES

To the Stockholders of CanArgo Energy Corporation:

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

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

The financial statements for 2004 and 2003 have been audited by the independent accounting firm of L J Soldinger Associates LLC, as indicated in their report. The financial statements for 2002 were audited by the independent accounting firm of PricewaterhouseCoopers, LLP as indicated in their report. Management has made available to its outside auditors all the Company s financial records and related data and minutes of directors and audit committee meetings.

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

/s/Dr. David Robson Chief Executive Officer	/s/Vincent McDonnell Chief Financial Officer

March 15, 2005

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of CanArgo Energy Corporation as of December 31, 2004 and 2003, and the related consolidated statements of operations, comprehensive loss, stockholders equity, and cash flows for the years then ended. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statements presentation. We believe that our audits provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of CanArgo Energy Corporation as of December 31, 2004 and 2003, and the consolidated results of operations, comprehensive loss, changes in stockholders equity and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

L J SOLDINGER ASSOCIATES LLC

Deer Park, Illinois, USA

March 15, 2005

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Directors and Shareholders of CanArgo Energy Corporation:

In our opinion, the accompanying consolidated statements of operations, stockholders equity and cash flows present fairly, in all material respects, the results of operations and cash flows of CanArgo Energy Corporation and its subsidiaries for the year ended December 31, 2002 in conformity with accounting principles generally accepted in the United States. These financial statements are the responsibility of the Company s management; our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion. We have not audited the consolidated financial statements of CanArgo Energy Corporation for any period subsequent to December 31, 2002.

The accompanying financial statements have been prepared assuming the Group will continue as a going concern. As discussed in Note 1, Basis of Presentation, to the consolidated financial statements, the Group is reliant on raising additional significant financing from external sources in order to recover the carrying value of its undeveloped and unproved properties and without additional financing there is substantial doubt about the Group s long term ability to continue as a going concern. Management s plans in regard to these matters are described in Note 1, Basis of Presentation. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

PricewaterhouseCoopers LLP

London, England
March 24 , 2003, except for Note 19 paragraph 10, as to which the date is April 9, 2004

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CANARGO ENERGY CORPORATION
Consolidated Balance Sheets
(Expressed in United States dollars)

	December, 31 2004	2003
Cash and cash equivalents	**$ 24,617,047**	$ 3,472,252
Restricted cash	**1,400,000**	
Accounts receivable	**2,526,442**	161,772
Crude oil inventory	**253,858**	468,793
Prepayments	**1,517,836**	961,588
Assets held for sale	**600,000**	10,346,077
Other current assets	**121,610**	206,532
Total current assets	**$ 31,036,793**	$ 15,617,014
Capital assets, net (including unevaluated amounts of $25,102,945 and $25,937,794 respectively)	**72,995,666**	57,668,233
Prepaid financing fees	**648,507**	
Investments in and advances to oil and gas and other ventures net	**478,632**	75,000
Total Assets	**$ 105,159,598**	$ 73,360,247
LIABILITIES AND STOCKHOLDERS EQUITY		
Accounts payable trade	**$ 2,331,945**	$ 483,282
Advance from joint venture partner		773,146
Loans payable	**1,500,000**	102,179
Other liabilities	**3,080,839**	5,473,823
Income taxes payable		97,500
Accrued liabilities	**172,117**	349,487
Liabilities held for sale		4,447,706
Total current liabilities	**$ 7,084,901**	$ 11,727,123
Long term debt	**832,165**	
Provision for future site restoration	**422,000**	152,000
Total Liabilities	**8,339,066**	11,879,123
Minority interest in subsidiaries		4,772,683
Commitments and contingencies		
Stockholders equity:		
Common stock, par value $0.10; authorized 300,000,000 shares; shares issued, issuable and outstanding 195,212,089 at 2004 and 105,617,988 at 2003	**19,521,208**	10,561,798
Capital in excess of par value	**184,141,618**	146,401,804
Deferred compensation expense	**(1,976,102)**	

Accumulated other comprehensive income (deficit)		(146,463)
Accumulated deficit	**(104,866,192)**	(100,108,698)
Total stockholders equity	**$ 96,820,532**	$ 56,708,441
Total Liabilities and Stockholders Equity	**$ 105,159,598**	$ 73,360,247

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

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CANARGO ENERGY CORPORATION
Consolidated Statements of Operations and Comprehensive Loss
(Expressed in United States dollars)

	For Years Ended December 31,		
	2004	2003	2002
Operating Revenues from Continuing Operations:			
Oil and gas sales	**$ 9,574,520**	$ 7,881,172	$ 4,163,201
Other		223,608	1,322,554
	9,574,520	8,104,780	5,485,755
Operating Expenses:			
Field operating expenses	**2,320,756**	1,051,905	1,537,917
Direct project costs	**1,434,114**	1,028,682	1,428,638
Selling, general and administrative	**5,929,256**	3,228,982	3,493,828
Non cash stock compensation expense	**1,395,036**	276,507	
Depreciation, depletion and amortization	**2,881,020**	3,294,086	2,316,774
Impairment of oil and gas properties, ventures and other assets	**174,812**		1,600,000
Loss (Gain) on dispositions	**(1,606,274)**	(616,741)	10,725
	12,528,720	8,263,421	10,387,882
Operating Income (Loss) from Continuing Operations	**(2,954,200)**	(158,641)	(4,902,127)
Other Income (Expense):			
Interest, net	**(902,130)**	(35,386)	32,413
Foreign exchange gains (losses)	**(447,455)**	(511,370)	128,579
Other	**(790,689)**	(123,541)	(822,908)
Equity (Loss) income from investments	**(205,230)**	65,544	86,059
Total Other Income (Expense)	**(2,345,504)**	(604,753)	(575,857)
Loss from Continuing Operations Before Minority Interest and Taxes	**(5,299,704)**	(763,394)	(5,477,984)
Income taxes			
Minority interest in loss of consolidated subsidiaries		7,406	58
Loss from Continuing Operations	**(5,299,704)**	(755,988)	$ (5,477,926)
Net Income (Loss) from Discontinued Operations, net of taxes and minority interest	542,210	(6,607,517)	150,225
Loss Before Cumulative Effect of Change in Accounting Principle	**(4,757,494)**	**(7,363,505)**	(5,327,701)
Cumulative effect of change in accounting principle		41,290	
Net Loss	**$ (4,757,494)**	**$ (7,322,215)**	**(5,327,701)**

Weighted average number of common shares outstanding						
- Basic		**134,005,490**		99,432,000		83,869,579
- Diluted		**134,005,490**		99,432,000		83,869,579
Basic and Diluted Net Loss Per Common Share						
- from continuing operations	**$**	**(0.04)**	$	(0.01)	$	(0.06)
- from discontinued operations	**$**		$	(0.07)	$	
- cumulative effect of change in accounting principle, net of Income tax	**$**		$		$	
Basic and Diluted Net Loss Per Common Share After Cumulative Effect of Change in Accounting Principle	**$**	**(0.04)**	**$**	**(0.08)**	**$**	**(0.06)**
Other Comprehensive Income:						
Foreign currency translation		146,463		(151,131)		4,668
Comprehensive Income (Loss)	**$**	**(4,611,031)**	$	(7,473,346)	$	(5,323,033)

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

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CANARGO ENERGY CORPORATION

Consolidated Statements of Cash Flows

(Expressed in United States dollars)

	For Years Ended December 31,		
	2004	2003	2002
Operating activities:			
Loss from continuing operations	**(5,299,704)**	(755,988)	(5,477,927)
Adjustments to reconcile net loss from continuing operations to net cash used in operating activities:			
Non-cash stock compensation expense	**1,395,036**	276,507	
Non-cash interest expense and amortization of debt discount	**653,313**	14,000	
Non-cash reduction in selling, general and administrative expenses	**(300,000)**		
Non-cash debt extinguishment expense	**349,923**		
Common stock issued for services	**118,400**		
Depreciation, depletion and amortization	**2,881,020**	3,294,086	2,316,774
Impairment of oil and gas properties and ventures	**174,812**		1,600,000
Equity loss (income) from investments	**205,230**	(65,544)	(86,059)
Loss (gain) on dispositions	**(1,606,274)**	(616,741)	10,725
Allowance for doubtful accounts	**5,803**	170,000	275,000
Minority interest in loss of consolidated subsidiaries		(7,406)	(58)
Changes in assets and liabilities:			
Restricted cash	**(1,400,000)**		
Accounts receivable	**(2,370,473)**	(81,169)	893,087
Inventory	**214,935**	(309,897)	214,922
Prepayments	**(12,560)**	54,767	29,713
Other current assets	**84,922**	(30,581)	(13,578)
Accounts payable	**1,848,664**	78,047	568,206
Deferred revenue	**(449,255)**	2,228,899	1,500,000
Income taxes payable	**(97,500)**	36,500	
Accrued liabilities	**(177,370)**	145,442	(196,176)
Net cash generated (used) by operating activities	**(3,781,078)**	4,430,922	1,634,629
Investing activities:			
Capital expenditures	**(11,190,290)**	(5,283,388)	(10,735,152)
Acquisitions, net of cash acquired			(50,000)
Proceeds from disposition of investments		1,000,000	13,435
Proceeds from disposition of subsidiary	**2,107,001**		
Investments in oil and gas and other ventures	**(383,862)**		
Repayments from oil and gas and other ventures		114,428	346,059
Advance proceeds from the sale of CanArgo Standard Oil Products		1,443,729	
Advance proceeds from the sale of CanArgo Petroleum Refining Limited		301,195	
Change in non cash working capital items	**(499,933)**	(804,732)	1,994,376

Net cash used in investing activities	**(9,967,084)**	(3,228,768)	(8,431,282)
Financing activities:			
Proceeds from sale of common stock	**37,999,516**		1,790,948
Share issue costs	**(4,543,845)**		(162,215)
Deferred offering costs	**(309,318)**		
(Repayment of) Advances from minority interest			1,546,137
Advances from joint venture partner	**290,000**	1,427,612	
Payments of joint venture obligations	**(1,063,146)**	(654,466)	
Proceeds from loans	**3,806,000**	380,000	
Repayment of loans	**(1,408,179)**	(277,821)	
Net cash provided by financing activities	**34,771,028**	875,325	3,174,870
Net cash flows from assets and liabilities held for sale	**121,929**	(190,227)	(683,308)
Net increase (decrease) in cash and cash equivalents	**21,144,795**	1,887,252	(4,305,091)
Cash and cash equivalents, beginning of period	**3,472,252**	1,585,000	5,890,091
Cash and cash equivalents, end of period	**$ 24,617,047**	$ 3,472,252	$ 1,585,000

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

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CANARGO ENERGY CORPORATION

Consolidated Statements of Stockholders Equity
(Expressed in United States dollars)

	Common Stock Number of Shares Issued and Issuable	Par Value	Additional Paid-In Capital	Deferred Compensation Expense	Accumulated Other Comprehensive Income (Loss)	Accumulated Deficit	Total Stockholders Equity
Balance, December 31, 2001	91,859,620	$ 9,185,962	$ 143,778,081	$	$	$ (87,458,782)	$ 65,505,261
Shares issuable upon exchange of CanArgo Oil & Gas, Inc. Exchangeable Shares without receipt of further consideration	148,826	14,883	279,436				294,319
Total, December 31, 2001	92,008,446	9,200,845	144,057,517			(87,458,782)	65,799,580
Less shares issuable at beginning of year	(148,826)	(14,883)	(279,436)				(294,319)
Issuance of common stock upon exchange of CanArgo Oil & Gas, Inc. Exchangeable Shares	148,826	14,883	279,436				294,319
Shares issued pursuant to private placement February 2002	5,210,000	521,000	1,241,433				1,762,433

Shares issued pursuant to private placement May 2002	137,760	13,775	14,740				28,515
Share issuance costs			(162,215)				(162,215)
Current year adjustment					4,668		4,668
Net loss						(5,327,701)	(5,327,701)
Total, December 31, 2002	97,356,206	$ 9,735,620	$ 145,151,475	$	$ 4,668	$ (92,786,483)	$ 62,105,280
Shares issued pursuant to Norio buy-out September 2003	6,000,000	$ 600,000	$ 540,000	$	$	$	$ 1,140,000
Shares issued pursuant to Manavi buy-out December 2003	2,000,000	200,000	460,000				660,000
Shares issued pursuant to Standby Equity Distribution Agreement	261,782	26,178	(26,178)				
Change in accounting policy pursuant to the Company electing to utilize the prospective method of transitioning to fair value method of accounting for stock-based compensation under SFAS No. 148			276,507				276,507

Current year adjustment					(151,131)		(151,131)
Net loss						(7,322,215)	(7,322,215)
Total, December 31, 2003	105,617,988	$ 10,561,798	$ 146,401,804	$	$ (146,463)	$ (100,108,698)	$ 56,708,441

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

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CANARGO ENERGY CORPORATION

Consolidated Statements of Stockholders Equity
(Expressed in United States dollars)

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

(CEOCast)					
Issue of Warrants to purchase 1 1 million shares pursuant to a loan loan agreement			754,000		754,000
Issue of Warrants to purchase 300,000 shares pursuant to a Loan agreement			197,040		197,040
Stock based compensation under SFAS 148			3,371,138	(1,976,102)	1,395,036
Shares issued pursuant to Standby Equity Distribution Agreement (Cornell Capital)	425,000	42,500	182,750		225,250
Issue of Warrants to purchase 1 million shares pursuant to a Loan agreement			263,786		263,786
Shares issued pursuant to a Gobal public offering	75,000,000	7,500,000	30,000,000		37,500,000
Shares issue costs			(4,543,845)		(4,543,845)

Shares issued pursuant to CanArgo Norio Limited Buy-Out	6,000,000	600,000	3,720,000				4,320,000
Shares issued pursuant to Consultancy agreement (CEOCast)	80,000	8,000	52,800				60,800
Current year adjustment					146,463		146,463
Net loss						(4,757,494)	(4,757,494)
Total, December 31, 2004	195,212,089	$ 19,521,208	$ 184,141,618	$ (1,976,102)	$	$ (104,866,192)	$ 96,820,532

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

CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 1 NATURE OF OPERATIONS

CanArgo Energy Corporation, headquartered in Guernsey, British Isles, and its consolidated subsidiaries (collectively CanArgo , we , our , us), is an integrated oil and gas company operating predominately within the Republic of Georg Our principal activity is the acquisition of interests in and development of crude oil and natural gas fields. In 2002 and 2003, we approved a plan to sell CanArgo Standard Oil Products Limited (CSOP), the Ukrainian development projects, the Georgian American Oil Refinery Limited (GAOR) and a generating power unit. The corresponding assets and liabilities of these entities have been classified as Assets held for sale and Liabilities held for sale for all periods presented and the results of operations have been classified as discontinued for all periods presented. The minority interest related to CSOP and GAOR has not been reclassified for any of the periods presented, however net income from discontinued operations is disclosed net of taxes and minority interest.

We have incurred recurring operating losses, and our operations did not generate positive cash flows in 2001. Although our operations did generate positive cash flows in 2002, our auditors at the time, expressed a doubt as to our ability to continue as a going concern as at December 31, 2002 and to pursue our principal activities of acquiring interests in and developing oil and gas fields which were dependent upon us reducing costs, generating funds from internal sources including the sale of certain non-core assets, external sources and, ultimately, maintaining sufficient positive cash flows from operating activities. The prior auditor s opinion does not extend to the financial statements as of December 31, 2004 and December 31, 2003.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

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

Consolidation

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

Equity Method

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

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

Use of Estimates in the Preparation of Financial Statements

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

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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

Cash and Cash Equivalents

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

Fair Value of Financial Instruments

The carrying amounts reflected in the consolidated balance sheets for cash and equivalents, short-term receivables and short-term payables approximate their fair value due to the short maturity of the instruments. The carrying value of the long-term note payable with detachable warrants reflects a discount for the value of warrants and was $832,165 at December 31, 2004. The face amount of the note payable is $1,050,000. The carrying value of the short-term debt approximates fair value as the debt bears interest at a market rate.

Concentration of Credit Risk

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

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

Reclassification

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

Allowance for Doubtful Debts

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

Inventories

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

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Capital Assets

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

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

Where proved reserves are established, capitalized costs are limited on a country-by-country basis (the ceiling test). The ceiling test is calculated as the sum of the present value of future net cash flows related to estimated production of proved reserves, using end-of-the-current-period prices, discounted at 10%, plus the lower of cost or estimated fair value of unproved properties, all net of expected income tax effects. Under the ceiling test, if the capitalized cost of the full cost pool exceeds the ceiling limitation, the excess is charged as an impairment expense.

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

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

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

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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

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

Discontinued Operations CanArgo Standard Oil Products petrol stations and additions thereto were depreciated over the estimated useful lives of the assets ranging from ten to fifteen years until operations were reclassified as discontinued.

Revenue Recognition

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

Advances

Advances received by CanArgo from joint venture partners, which are to be spent by us on behalf of the joint venture partners, are classified as payables and reflected in our cash flow statement within finance activities. When the cash advances are spent, the payable is reduced accordingly. These advances do not contribute to our operating profits and are accounted for/disclosed as balance sheet entries only within cash and payable to joint venture partner.

Foreign Operations

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

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Foreign Currency Translation

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

Income Taxes

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

Impairment of Long-Lived Assets

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

Dismantlement, Restoration and Environmental Costs

Effective January 1, 2003, we recognize liabilities for asset retirement obligations associated with tangible long-lived assets, such as producing well sites, offshore production platforms, and natural gas processing plants, with a corresponding increase in the related long-lived asset. The asset retirement cost is depreciated along with the property and equipment in the full cost pool. The asset retirement obligation is recorded at fair value and accretion expense, recognized over the life of the property, increases the liability to its expected settlement value. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded for both the asset retirement obligation and the asset retirement cost.

Upon adoption of this standard we recorded the fair value of its existing asset retirement obligations as if the liabilities had been initially accounted for in accordance with SFAS 143 using assumptions present at the date of adoption. The income statement effect of this treatment was recorded as a cumulative effect in accounting principle in the period of adoption. During 2003, we recorded a credit to income for the cumulative effect of change in accounting principle of $41,290, increased long-term liabilities to recognise our total obligation and increased net capital assets in accordance with the provisions of SFAS No. 143 to the amount of $82,000. We did not recognise deferred tax expense on the SFAS 143 credit as the group is in a net deferred tax asset position against which full allowance has been made as it is considered more likely than not that the deferred tax asset will not be realised. There was no impact on our cash flows as a result of adopting SFAS No. 143. The asset retirement obligation, which is included on the consolidated balance sheet in provision for future site restoration, was $422,000 at December 31, 2004. The pro-forma amounts, relating to 2002, assuming the new method of determination under SFAS 143, were not materially different to the amounts shown in the income statement and the balance sheet for the prior year.

	2004	2003
Beginning balance, January 1	151,000	123,290
Cumulative effect of change in accounting principle		(41,290)
New obligations incurred in 2004	270,000	
Liabilities settled in 2004		
Accretion of expense	14,000	
Revision in estimates, including timing	(13,000)	69,000
Balance at December 31	422,000	151,000

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Stock-Based Compensation Plans

Effective January 1, 2003, we adopted SFAS No. 123 *Accounting For Stock-Based Compensation* (SFAS 123), as amended by SFAS No. 148 *Accounting for Stock-Based Compensation Transition and Disclosure an amendment of FASB Statement No. 123*. We elected to utilize the prospective method of transitioning from the intrinsic value to the fair value method of accounting for stock-based compensation. Stock based awards in existence prior to 2003 will continue to be accounted for under APB Opinion No. 25 *Accounting for Stock Issued to Employees*, unless they are re-priced or modified.

Prior to 2003, we applied APB Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations in accounting for stock-based compensation. Under Opinion No. 25, stock-based employee compensation cost was not recognized in net income when stock options granted had an exercise price equal, or greater, to the market value of the underlying common stock on the date of grant.

The pro forma information regarding net loss and net loss per share is required by SFAS 123 and has been determined as if we had accounted for our employee stock options under the fair value method of that statement. The fair value for these options was estimated at the date of grant using a Black-Scholes option pricing model with the following weighted average assumptions for 2004, 2003 and 2002, respectively; risk free interest rates of 2.91%; dividend yields of 0%; volatility factors of the expected market price of CanArgo common stock of 80.47; and a weighted-average expected life of the options of four years. The following table illustrates the pro forma effect on net loss and net loss per share if the fair value based method had been applied to all outstanding and unvested awards for the years ended December 31, 2003 and 2002 where a difference occurred:

	For the Years Ended December 31,	
	2003	2002
Net Loss as reported	$ (7,322,215)	$ (5,327,701)
Add: Stock-based compensation cost, net of related tax effects, included in the determination of net income as reported	276,507	
Less: Stock-based compensation cost, net of related Tax effects, that would have been included in the determination of net income reported if the fair value based method had been applied to all awards	786,783	925,339
Pro forma net loss	(7,832,491)	(6,253,040)
Loss per share		
Basic and diluted as reported	(0.08)	(0.06)
Basic and diluted pro forma	(0.08)	(0.06)

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Recently Issued Pronouncements

In September 2004, the Securities and Exchange Commission issued Staff Accounting Bulletin (SAB) No. 106 which expressed the Staff s views regarding the application of Statement of Financial Accounting Standards (SFAS) No. 143 Accounting for Asset Retirement Obligations by oil and gas producing companies following the full-cost accounting method. SAB No. 106 specifies that subsequent to the adoption of SFAS No. 143 an oil and gas company following the full-cost method of accounting should include assets recorded in connection with the recognition of an asset retirement obligation pursuant to SFAS No. 143 as part of the costs subject to the full-cost ceiling limitation. The future cash outflows associated with settling the recorded asset retirement obligations should be excluded from the computation of the present value of estimated future net revenues used in applying the ceiling test. The Company will be required to adopt the provisions of SAB No. 106 prospectively in the first quarter of 2005 which will have no impact on the Company s results of operation or financial position.

In September 2004, the FASB issued a FASB Staff Position to clarify that the scope exception in paragraph 8(b) of SFAS No. 142 includes the balance sheet classification and disclosures for drilling and mineral rights of oil and gas producing companies. Therefore, our historical practice of including the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties under SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, has been affirmed by the new FSP.

NOTE 3 RESTRICTED CASH

Restricted cash consisted of the following at December 31:

	2004	2003
Restricted cash	$ 1,400,000	$
	$ 1,400,000	$

Restricted cash of $1,400,000 at December 31, 2004 relates to money placed in a third party escrow account in October 2004, to fund part of the horizontal development program at the Ninotsminda and Samgori Fields in Georgia. These funds are committed until such time as we complete the second well in the horizontal development program.

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 4 ACCOUNTS RECEIVABLE

Accounts receivable consisted of the following at December 31:

	2004	2003
Trade receivables before allowance for doubtful debts	$ 1,081,055	$ 951,911
Allowance for doubtful debts	(866,239)	(821,921)
Due from Samgori PSC partner	1,057,534	
Insurance receivable	1,047,359	
Other receivables	206,733	31,782
	$ 2,526,442	$ 161,772

Bad debt expense for 2004, 2003 and 2002 was $5,803, $170,000 and $250,000 respectively, and is reflected under other income in the statement of operations.

In September 2004, we had a blow out of our N100 well. Our insurers will cover 80% of the costs associated with the blow out. Costs incurred as of December 31, 2004 were $1,309,198 and $1,047,357 is recorded as a receivable.

Included in receivables is $1,057,534 due from Georgian Oil Samgori Limited for their share of capital expenditure on our horizontal well drilling program. We have funded 100% of the costs so far and should Georgian Oil Samgori Limited not be in a position to fund their share of the program costs, we are entitled to continue the project at our sole risk at which time the receivable would be transferred to oil and gas properties.

NOTE 5 CRUDE OIL INVENTORY

Inventory consisted of the following at December 31:

	2004	2003
Crude oil	$ 253,858	$ 468,793
	$ 253,858	$ 468,793

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 6 CAPITAL ASSETS

Capital assets, net of accumulated depreciation and impairment, include the following at December 31, 2004:

	Cost	Accumulated Depreciation And Impairment	Net Capital Assets
Oil and Gas Properties			
Proved properties	$ 61,458,503	$ (23,382,448)	$ 38,076,055
Unproved properties	25,102,945		25,102,945
	86,561,448	(23,382,448)	63,179,000
Property and Equipment			
Oil and gas related equipment	14,119,443	(4,693,368)	9,426,075
Office furniture, fixtures and equipment and other	689,439	(298,848)	390,591
	14,808,882	(4,992,216)	9,816,666
	$ 101,370,330	$ (28,374,664)	$ 72,995,666

Capital assets, net of accumulated depreciation and impairment, include the following at December 31, 2003:

	Cost	Accumulated Depreciation And Impairment	Net Capital Assets
Oil and Gas Properties			
Proved properties	$ 44,327,133	$ (21,084,230)	$ 23,242,903
Unproved properties	25,937,794		25,937,794
	70,264,927	(21,084,230)	49,180,697
Property and Equipment			
Oil and gas related equipment	12,350,840	(4,240,698)	8,110,142
Office furniture, fixtures and equipment and other	1,235,876	(858,482)	377,394
	13,586,716	(5,099,180)	8,487,536
	$ 83,851,643	$ (26,183,410)	$ 57,668,233

Oil and Gas Properties

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

As a result of application of the ceiling test limitation, CanArgo recorded a write-down in 2002 of oil and gas properties of $1,600,000. In 2003 and 2004, CanArgo did not need to write-down oil and gas properties due to the ceiling test.

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

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 6 CAPITAL ASSETS (Continued)

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

Unproved property additions relate to our exploration activity in the period. Oil and gas related equipment includes new or refurbished drilling rigs and related equipment, all of which are located in the Republic of Georgia.

Property and Equipment

Property and Equipment, Oil and gas related equipment includes drilling rigs and related equipment currently in use by us in the development of the Ninotsminda and Samgori Fields.

NOTE 7 PREPAID FINANCING FEES

Prepaid financing fees at December 31 relate to the Cornell SEDA:

	2004	2003
Prepaid financing fees	$ 648,507	$
	$ 648,507	$

Prepaid financing fees are commissions and professional fees related to the Stand by Equity Distribution Agreement with Cornell Capital Partners LP. As proceeds are received under this agreement, the prepaid financing fees will offset capital in excess of par value. See Note 16 Stockholders Equity for further detail regarding the Stand by Equity Distribution Agreement with Cornell Capital Partners LP.

NOTE 8 INVESTMENT IN AND ADVANCES TO OIL AND GAS AND OTHER VENTURES

We have acquired interests in oil and gas and other ventures through less than majority interests in corporate and corporate-like entities. A summary of our net investment in and advances to oil and gas and other ventures consisted of the following at December 31:

Investments in and Advances to Oil and Gas and Other Ventures	2004	2003
Kazakhstan Through 45% ownership of Tethys Petroleum Investments Limited	$ 683,862	$
Other Investments net of impairment		75,000
Total Investments in and Advances to Oil and Gas and Other Ventures	$ 683,862	$ 75,000
Equity in Profit (Loss) of Oil and Gas and Other Ventures Kazakhstan	(205,230)	

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 8 INVESTMENT IN AND ADVANCES TO OIL AND GAS AND OTHER VENTURES (Continued)

	2004	2003
Investments in and Advances to Oil and Gas and Other Ventures		
Cumulative Equity in Profit (Loss) of Oil and Gas and other ventures	(205,230)	
Total Investments in and Advances to Oil and Gas and Other Ventures, Net of Equity Loss	$ 478,632	$ 75,000

Kazakhstan Project

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

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

In 2004 our total investment and advances amounted to $683,862 which were comprised of $17,366 as our initial investment and $666,496 of advances. Our investment and advances were comprised of cash of $383,862 and $300,000 in non-cash management fees which have been netted against our general and administrative expenses. In addition, we accrued an additional $30,215 in interest on our advances and fees to TPI during 2004.

As discussed in Note 2, we have chosen to use our equity ownership percentage as the basis for recording our portion of our investees loss and therefore first reduced our investment of $17,366 to zero and then applied the remaining equity losses of $187,864 to reduce the carrying value of our advances to $478,632.

At December 31, 2004 the carrying value of our investment and advances exceeded the underlying equity in the net assets of the investee by $190,312.

Other Investments

In May 1998, we 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 a 75.1% ownership interest. Seismic data 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 have fully impaired our investment of $75,000 in the Caspian exploration project as of December 31, 2004.

CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 9 ADVANCE FROM JOINT VENTURE PARTNER

In 2004, we received $290,000 and in 2003 we received payments in the amount of $1,427,612 from Georgian Oil in accordance with the Norio farm-in agreement. In 2003, CanArgo Norio signed a farm-in agreement relating to the Norio Production Sharing Agreement (Norio PSA) with a wholly owned subsidiary of Georgian Oil, the Georgian State Oil Company. The farm-in agreement obligates Georgian Oil to advance us up to $2,000,000 to deepen to a planned depth of 16,400 feet (5,000 metres) the MK-72 well in return for a 15% interest in the contractor share of the Norio PSA. Georgian Oil also has an option, exercisable for a limited period after completion of the well, to increase its interest to 50% of the contractor share of the Norio PSA on payment to CanArgo Norio of US$ 6,500,000. If Georgian Oil exercises this option under the farm-in agreement, it loses its rights to exercise the option Georgian Oil is entitled to under the Norio PSA itself. The full amount of the $1,717,612 advanced to us as of December 31, 2004 from Georgian Oil, was spent on the MK-72 well by December 31, 2004.

NOTE 10 LOANS PAYABLE AND LONG TERM DEBT

Loans payable at December 31 consisted of the following:

	2004	2003
Short term loans payable		
Short term loan	$	$ 102,179
Promissory Notes	1,500,000	
Loans payable	$ 1,500,000	$ 102,179

Long term debt		
Long term loans with detachable warrants	$ 1,050,000	$
Unamortized debt discount	(217,835)	
Long term debt	$ 832,165	$

Short term loan payable of $102,179 at December 31, 2003 related to a short-term secured loan facility that matured and was paid in full on February 27, 2004.

In order to insure timely procurement of long lead items for our drilling program in Georgia and for working capital purposes during 2004, we entered into a number of loan agreements as described below.

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 10 LOANS PAYABLE AND LONG TERM DEBT (Continued)

On April 26, 2004, we entered into two loan and warrant agreements, one with Salahi Ozturk in which Mr. Ozturk advanced us $1,000,000 in exchange for which we issued to Mr. Ozturk a promissory note in the amount of $1,000,000 (Original Loan) and the other for $306,000 with CA Fiduciary Services, Ltd Trustee for the SP525A Settlement (CA), for which we issued to CA a promissory note in the amount of $306,000. The notes to Mr. Ozturk and to CA bear interest at the rate of 7.5% per annum and had a term of six months. In addition to the promissory notes, we issued Mr. Ozturk a warrant to subscribe up to 1,000,000 shares of our common stock, with an exercise price of $1.00 per share and a term of five years from the date of grant and we issued to CA a warrant to subscribe up to 300,000 shares of our common stock, with an exercise price of $1.05 per share and a term of five years from the date of grant.

Under Accounting Principles Board (APB) 14: Accounting for Convertible Debt and Debt Issued with Stock Purchase Warrants we allocated the proceeds from the issuances of the promissory note and warrants based on a fair value basis of each item. The fair value of the warrants was determined to be $754,000 for the 1,000,000 warrants issued to Mr. Ozturk and $197,040 for the 300,000 warrants issued to CA and was recorded as a discount to the value of the promissory note.

We used the following assumptions to determine the fair value of the debt and warrants:

	Ozturk Loan	CA Loan
Stock price on date of grant	$ 0.87	$ 0.78
Risk free rate of interest	1.19%	1.15%
Expected life of warrant months	60	60
Dividend rate		
Historical volatility	138%	132%

The discounts were amortized to interest expense over the life of the promissory note using the effective interest method. The effective interest rate for the Ozturk and CA Loans were 218% and 188%, respectively.

As a result of our completing an equity offering on September 22, 2004, we repaid both the Original Loan to Mr. Ozturk and the CA loan on September 30, 2004. The payoff of the CA loan resulted in our expensing the remaining unamortized debt discount for that loan. On payment of the Original Loan to Mr. Ozturk, the lien covering 50% of the revenues of Ninotsminda Oil Company Limited was terminated.

On August 27, 2004, we entered into an amended and restated loan and warrant agreement (Amended Agreement) with Mr. Ozturk, amending the loan and warrant agreement between the parties dated April 26, 2004. Under the terms of the amended loan and warrant agreement, Mr. Ozturk agreed to cancel the original warrant agreement and to advance the Company an additional $1,050,000 (Additional Loan) and extend the maturity date of the original loan to one year from six months. The Additional Loan is repayable two years and one day from the date of the Amended Agreement unless it has previously been converted. Corporate finance fees of $50,000 were paid in respect of the Additional Loan. Interest is payable on the Additional Loan at a rate of 7.5% per annum. The first interest payment was due December 31, 2004 and was to include interest for the period from August 27, 2004 until December 31, 2004. The Additional Loan is convertible into shares of CanArgo Common Stock (Conversion Stock) at 15% above a market price of $0.60 in effect when the agreement was reached, subject to customary anti-dilution adjustments. We have the option to force conversion of the Additional Loan if our share price exceeds 160% of $0.60 (or $0.96 per share) for a period of 20 consecutive trading days. No conversion is possible for a period of one year from the date of the Amended Agreement.

In consideration for advancing funds under the Amended Agreement and the Additional Loan, we issued to Mr. Ozturk a warrant to subscribe for 2,000,000 shares of our common stock at an exercise price 5% above the market price of our common stock on the date of grant, subject to customary anti-dilution adjustments. The new warrant was issued on August 27, 2004 and is exercisable for a period of four years commencing one year from the date of the Amended Agreement. The warrants are transferable to non-US persons and may only be exercised outside the US.

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 10 LOANS PAYABLE AND LONG TERM DEBT (Continued)

Under the provisions of Emerging Issues Task Force (EITF) 96-19 Debtor s Accounting for a Modification or Exchange of Debt Instruments , the Company has treated the Amended Agreement as extinguishment of the Original Loan due to its determination that the provisions of the Amended Agreement represented a substantial modification of terms as defined in the EITF. The result of the extinguishment was for the Company to record a loss on extinguishment in the amount of $349,923, which represented the unamortized portion of the discount of the original loan on the date of the Amended Agreement.

The Company s stock price at the time of the Amended Agreement was $0.51; consequently, pursuant to EITF 98-5 Accounting for Convertible Securities with Beneficial Conversion Features or Contingently Adjustable Conversion Ratios and EITF 00-27 Application of Issue No. 98-5 to Certain Convertible Instruments , the issuance of the Additional Loan and detachable warrants resulted in a discount being recorded in the amount of $263,786, which resulted from the relative fair value of the warrants, as determined using the black-scholes model, and will be amortized over the term of the Notes using the effective interest method.

We used the following assumptions to determine the fair value of the debt and warrants:

	Additional Loan
Stock price on date of grant	$ 0.51
Risk free rate of interest	2.51%
Expected life of warrant months	48
Dividend rate	
Historical volatility	108%

The discounts are being amortized to interest expense over the life of the promissory note using the effective interest method. The effective interest rate was 18.9%. As of December 31, 2004 we had amortized $45,951 of the debt discount as interest expense.

On May 19, 2004, we signed a promissory note with Cornell Capital Partners, L.P. (Cornell Capital) whereby Cornell Capital agreed to advance us the sum of $1,500,000. This amount was originally 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 filed with the SEC on May 6, 2004 (Reg. No. 333-115261) was declared effective. Since if the promissory note was not repaid in full when due, interest accrued on the outstanding principal owing at the rate of 12% per annum. We paid to Cornell Capital a commitment fee of 5% of the principal amount of the promissory note which shall be set-off against the first $75,000 of fees payable by us to Cornell Capital under the Standby Equity Distribution Agreement dated February 11, 2004 (See Liquidity and Capital Resources below for a more detailed discussion). The Registration Statement was declared effective on February 3, 2005, we have repaid the promissory note in full by making a series of takedowns in February and March 2005 under the Standby Equity Distribution Agreement.

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.

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NOTE 10 LOANS PAYABLE AND LONG TERM DEBT (Continued)

CANARGO ENERGY CORPORATION
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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 Company s common stock issued pursuant to the takedown under the Equity Line completed on February 21, 2005 the proceeds of which should have been credited to the Company under its 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 $569,500 to CanArgo.

As at March 14, 2005 we have 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.

NOTE 11 OTHER LIABILITIES

Other liabilities consisted of the following at December 31:

	2004	2003
Prepaid sales and oil sales security deposit	$ 2,699,644	$ 3,228,899
Advanced proceeds, less costs of the sale of subsidiary		1,943,729
Prepaid licence fees	80,000	
Advanced proceeds from the sale of other assets	301,195	301,195
	$ 3,080,839	$ 5,473,823

See Note 19 for details of the sale of the subsidiary classified as discontinued operation.

NOTE 12 ACCRUED LIABILITIES

Accrued liabilities consisted of the following at December 31:

	2004	2003

Professional fees	$ 93,001	$ 231,396
Other	79,116	118,091
	$ 172,117	$ 349,487

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CANARGO ENERGY CORPORATION
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NOTE 13 MINORITY INTEREST

CanArgo Norio Limited

In September 2003, CanArgo Norio Limited (CNL) signed a Farm-In agreement (the Agreement) relating to the Norio PSA with a wholly owned subsidiary of Georgian Oil, the Georgian State Oil Company (Georgian Oil). Georgian Oil is already a party to the Norio PSA as the commercial representative of the State. The Agreement obligates Georgian Oil to pay up to $2,000,000 to complete the MK-72 well on the Norio prospect in return for a 15% interest in the contractor share of the Norio PSA. Georgian Oil will also have an option (the Option) exercisable for a limited period after completion of the well, to increase its interest to 50% of the contractor share of the Norio PSA on payment to CNL of $6,500,000.

Coincident with the Georgian Oil farm-in, we concluded a transaction to purchase some of the minority interests in CNL by a share swap for shares in CanArgo. Through this exchange we acquired an additional 10.8% interest in CNL increasing our interest to 75%. This maintains our effective interest in the Norio PSA after Georgian Oil has completed the first stage of the farm-in at approximately 63.7%. The purchase was achieved by issuing 6,000,000 restricted CanArgo shares to the minority interest holders in CNL. Of the interests in CNL, 4% were owned by Provincial Securities Limited, a company to which Mr. Russell Hammond, a non-executive director of CanArgo, is a financial advisor. Provincial Securities Limited received 2,273,523 shares of common stock in return for their interest. In the event that Georgian Oil exercises the Option and pays the required $6,500,000 to CNL we would be obligated to issue a further 3,000,000 restricted shares to the minority interest holders.

On September 30, 2004 we announced that we had increased our interest in CNL, by buying out the remaining minority shareholder in that company, NPET Oil Limited. CNL will now become a wholly owned subsidiary of CanArgo. Following completion of the Georgian Oil farm-in to the Norio PSA, CNL will hold an 85% interest in the Norio PSA. CNL also holds 100% of the contractor s interest in the Block XI^G and XI^H Production Sharing Contract (Tbilisi PSC). This transaction has therefore increased our interest in the Norio PSA by 21.25%, and by 25% in the Tbilisi PSC. We have issued 6,000,000 restricted shares of our common stock valued at $4,320,000 to NPET Oil Limited in connection with this transaction. Upon recording this transaction, minority interest of $1,351,022 was reduced to $0 and oil and gas properties increased by $2,968,978. At the same time, our commitment under the Norio PSA and the original shareholders agreement for a bonus payment of $800,000 to be paid by us to the other shareholders should commercial production be obtained from the Middle Eocene or older strata and a second bonus payment of $800,000 should production exceed 250 tonnes (approximately 1,900 barrels) of oil per day over any 90 day period has terminated.

CanArgo Standard Oil Products Limited

In September 2002, we approved a plan to sell our interest in CanArgo Standard Oil Products Limited (CSOP), a petroleum product retail business in Georgia, to finance our Georgian and Ukrainian development projects. In October 2002, we reached agreement with Westrade Alliance LLC, an unaffiliated company, to sell our wholly owned subsidiary, CanArgo Petroleum Products Limited (CPPL), which held our 50% interest in CSOP for $4,000,000 in an arms-length transaction, with legal ownership being transferred upon receipt of final payment due 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. The results of

CSOP s operations have been presented for financial statement purposes as discontinued operations. See Note 19 Discontinued Operations

CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 13 MINORITY INTEREST (Continued)

Georgian American Oil Refinery

In November 2000, we completed the acquisition of a 51% interest in the Georgian American Oil Refinery (GAOR), a company which owns a small refinery located at Sartichala, Georgia. From that date, GAOR became a subsidiary of CanArgo and its results have been included in our consolidated financial statements. However, due to operational difficulties and changes to the fiscal system in Georgia, GAOR ceased to operate during 2001.

As a result of the uncertainty as to the ultimate recoverability of the carrying value of the refinery, we recorded in 2001 a write-down of the refinery s property, plant and equipment of approximately $3,500,000. During 2003, a debit balance of $1,274,895 in minority interest was written-off due to a change in the intentions of our minority interest owner and a plan to dispose of the asset. In 2004, we came to an agreement to sell our interest in the refinery. Our interest in the refinery was sold in February 2004.

NOTE 14 COMMITMENTS AND CONTINGENCIES

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

At December 31, 2004, we had the contingent obligation to issue an aggregate of 187,500 shares of our Common Stock to Fielden Management Services PTY, Ltd (a third party management services company), subject to the satisfaction of conditions related to the achievement of specified performance standards by the Stynawske Field project, an oil field in Ukraine in which we had a previous interest.

If Georgian Oil exercises an option available to it under the terms of the Norio farm-in agreement signed in September 2003, we would issue a further 3,000,000 restricted shares to Provincial Securities Limited and Georgian British Oil Services Company (GBOSC), the minority interest holders from whom we acquired an additional 10.8% interest in CanArgo Norio Limited.

Under the Production Sharing Contract for Blocks XI^G and XI^H (the Tbilisi PSC) in the Republic of Georgia our subsidiary CanArgo Norio Limited 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 contract which is September 29, 2003. The total commitment over the next four years is $350,000.

In 2002, the Participation Agreement for the three well exploration program on the Ninotsminda area with AES was terminated without AES earning any rights to any of the Ninotsminda area reservoirs. We therefore have no present obligations in respect of AES. However, under a separate Letter of Agreement, if gas from the Sub Middle Eocene is discovered and produced from the exploration area covered by the Participation Agreement, AES will be entitled to recover at the rate of 15% of future gas sales from the Sub Middle Eocene, net of operating costs, approximately $7,500,000, representing their prior funding under the Participation Agreement.

Ninotsminda Oil Company Limited has a commitment to repay $2,300,000 arising from security deposit payments under an oil sales agreement with Primrose Financial Group (Primrose) dated May 5, 2004. The security may be paid in oil at the end of the contract period. In February 2005 we cancelled our oil sales agreement with Primrose and repaid the advance in full. See Note 23 Subsequent Events.

CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 14 COMMITMENTS AND CONTINGENCIES (Continued)

In April 2004, we acquired a 50% interest in the Samgori (Block XI^{B}) Production Sharing Contract (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 will be drilled on the Samgori Field. Upon completion of well S302 in October 2004, which was funded 100% by us, we satisfied our commitment to GOSL under the acquisition agreement. The remainder of the drilling program will 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 is due to be completed within 36 months, is anticipated to be up to $13,500,000.

The original Contractor party to the Samgori PSC, National Petroleum Limited (NPL), has 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 is not completed in part within 18 months of the work commencement date (WCD) and in full within 36 months of the WCD. Furthermore, 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). The Cost Recovery pool includes the $37,528,964 costs previously incurred by NPL. The balance of production (Profit Oil) is allocated on a 60/40 basis between the State and the Contractor parties respectively. While GOSL and CSL continue to have unrecovered costs, they will receive 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 will receive 30% of Profit Oil (net 15% to us). The allocation of a share of production to the State, however, relieves the Contractor parties of all obligations they would otherwise have to pay the Republic of Georgia for taxes, duties and levies related to activities covered by the Samgori PSC. After NPL s costs are 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 shall 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.

Upon completion of the acquisition of an interest in the Samgori PSC we had a contractual obligation to issue 4,000,000 shares of CanArgo Common Stock to Europa Oil Services Limited (Europa), an unaffiliated company in connection with a consultancy agreement with Europa in relation to this acquisition. On April 16, 2004 Europa was issued with 4,000,000 restricted shares of CanArgo Common Stock valued at $3,880,000 in an arms length transaction, which correspondingly increased our investment in oil and gas properties. A further 12,000,000 shares of CanArgo Common Stock are issuable upon certain production targets being met from future developments under the

Samgori PSC.

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CANARGO ENERGY CORPORATION
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NOTE 14 COMMITMENTS AND CONTINGENCIES (Continued)

Lease Commitments We lease office space under non-cancelable operating lease agreements. Rental expense for the years ended December 31, 2004, 2003 and 2002 was $379,102, $395,355 and $327,254 respectively. Future minimum rental payments over the next five years for our lease obligations as of December 31, 2004, are as follows:

2005	$ 363,550
2006	321,370
2007	312,630
2008	312,630
2009	312,630
Thereafter	156,315*
	$ 1,779,125

* This represents payments for 6 months in 2010.

No parent company guarantees have been provided by CanArgo with respect to our contingent obligations and commitments.

NOTE 15 CONCENTRATIONS OF CREDIT RISK

Our financial instruments that are exposed to concentrations of credit risk consist primarily of cash and cash equivalents, accounts receivable and advances to oil and gas investees. We place our temporary cash investments with high credit quality financial institutions. Accounts receivable relates primarily to entities active in the energy and manufacturing sectors. The concentration of credit risk associated with accounts receivable is reduced as our debtors are spread across several countries and industries.

NOTE 16 STOCKHOLDERS EQUITY

On July 8, 1998, at a Special Meeting of Stockholders, the stockholders of CanArgo approved the acquisition of all of the common stock of CanArgo Oil and Gas (CAOG) for Common Stock of the Company pursuant to the terms of an Amended and Restated Combination Agreement between those two companies (the Combination Agreement). Upon completion of the acquisition on July 15, 1998, CAOG became a subsidiary of CanArgo, and each previously outstanding share of CAOG common stock was converted into the right to receive 0.8 shares (the Exchangeable Shares) of CAOG which are exchangeable generally at the option of the holders for shares of CanArgo s Common Stock on a share-for-share basis.

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 16 STOCKHOLDERS EQUITY (Continued)

On January 24, 2002 we announced that we had established May 24, 2002 as the redemption date for all of the Exchangeable Shares of CAOG since the number of outstanding Exchangeable Shares had fallen below the minimum 853,071 share threshold. Each Exchangeable Share was purchased by CanArgo for shares of CanArgo

Common Stock on a share-for-share basis resulting in the issuance of an aggregate of 148,826 shares of Common Stock. No cash consideration was issued by CanArgo and the purchase did not increase the total number of shares of Common Stock of CanArgo deemed issued and issuable.

In February 2004, we announced that we had signed a Standby Equity Distribution Agreement that allows us, at our option, to issue shares to US-based investment fund Cornell Capital Partners LP up to a maximum value of $20,000,000 over a period of up to two years from the date on which the Registration Statement on Form S-3 registering for resale the shares under the Securities Act of 1933, as amended (Securities Act) is declared effective. The Registration Statement was declared effective by the SEC on February 3, 2005

The total number of shares of common stock authorized was 300,000,000 as of 31 December 2004 and 150,000,000 for 2003 and 2002.

As of December 31, 2004, we had 5,000,000 shares of $0.10 par value preferred stock authorized, of which none were outstanding. The Board of Directors may at any time issue additional shares of preferred stock and may designate the rights and privileges of a series of preferred stock without any prior approval by the stockholders.

During the years ended December 31, 2004 and 2003, the following transactions regarding CanArgo s Common Stock were consummated pursuant to authorization by CanArgo s Board of Directors or duly constituted committees thereof.

Year Ended December 31, 2004

In February 2004, 163,218 shares of our common stock were issued at $0.56 per share to Cornell Capital Partners, L.P. as part payment of the commitment fee payable pursuant to the Standby Equity Distribution Agreement between Cornell and the Company (Equity Line of Credit).

In February 2004, 30,799 shares of our common stock were issued at $0.33 per share to Newbridge Securities Corporation pursuant to the Placement Agent Agreement among CanArgo Energy Corporation, Newbridge Securities Corporation and Cornell Capital Partners in terms of which Newbridge advised the Company and acted as our exclusive placement agent in respect of the Equity Line of Credit.

In March 2004, 3,815,084 shares of CanArgo common stock were issued at an average of $0.13 per share as a result of employees exercising stock options.

In April, 2004 we issued 4,000,000 shares of CanArgo common stock at $0.94 per share to Europa Oil Services Limited pursuant to a consultancy agreement to acquire an interest in the Samgori PSC.

In July, 2004 we issued 80,000 shares of CanArgo common stock at $0.70 per share to CEOcast Inc in relation to a consultancy agreement between CanArgo and CEOcast Inc dated May 17, 2004. Such shares were issued in a transaction intended to qualify for an exemption from registration under the Securities Act afforded by

Section 4(2)

In July 2004, we issued 425,000 shares of our common stock at $0.50 per share to Cornell Capital Partners, L.P. as part payment of the commitment fee payable pursuant to the Standby Equity Distribution Agreement between Cornell and the Company (Equity Line of Credit).

CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 16 STOCKHOLDERS EQUITY (Continued)

In September 2004, we completed a global public offering (Global Offering) of 75 million shares of our common stock at an offering price of $0.50 per share. We raised gross proceeds of $37,500,000 and paid total commissions and expenses related to the Global Offering of $4,543,845 which resulted in net proceeds to the Company of $32,956,155.

In September, 2004 we issued 6,000,000 restricted shares of our common stock at $0.72 per share to NPET Oil Limited to increase our interest in CanArgo Norio Limited, by buying out the remaining minority shareholder in that company, NPET Oil Limited.

In November 2004, 80,000 shares of CanArgo common stock were issueable to CEOcast Inc at $0.76 in relation to a consultancy agreement between CanArgo and CEOcast.

Year Ended December 31, 2003

In September 2003, CanArgo issued 6,000,000 shares at $0.19 per share for purchase some of an additional 10.8% interest in CanArgo Norio.

In December 2003, CanArgo issued 2,000,000 shares at $0.33 per share upon completion of the purchase of the interest of the farm-in partner in the Manavi well.

In December 2003, CanArgo issued 261,782 shares at $0.33 per share upon completion of a Standby Equity Distribution Agreement that allowed CanArgo, at its option, to issue shares to US-based investment fund Cornell Capital Partners LP up to a maximum value of $6 million. This facility was terminated on February 11, 2004 when the Company entered into a further standby equity distribution agreement.

Year Ended December 31, 2002

In February 2002, CanArgo issued 5,210,000 shares at $0.34 per share upon completion of a private placement.

In May 2002, CanArgo issued 137,760 shares at $0.21 to David Robson, CanArgo s Chief Executive Officer, for gross proceeds of approximately $29,000 upon completion of a private placement.

In May, 2002 CanArgo redeemed all of the Exchangeable Shares of CAOG since the number of outstanding Exchangeable Shares had fallen below the minimum 853,071 share threshold. Each Exchangeable Share was purchased by CanArgo for shares of CanArgo Common Stock on a share-for-share basis resulting in the issuance of an aggregate of 148,826 shares of Common Stock. No cash consideration was issued by CanArgo and the purchase did not increase the total number of shares of Common Stock of CanArgo deemed issued and issuable.

CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 17 NET LOSS PER COMMON SHARE

Earnings (loss) per share is calculated in accordance with SFAS No. 128, Earnings Per Share. Basic and diluted earnings per share are provided for continuing operations, discontinued operations, cumulative effect of change of accounting principle and net income (loss). Basic earnings (loss) per share is computed based upon the weighted average number of shares of common stock outstanding for the period and excludes any potential dilution. Diluted earnings per share reflects potential dilution from the exercise of securities (warrants, options and convertible debt) into common stock. Outstanding options and warrants to purchase common stock are not included in the computation of diluted loss per share because the effect of these instruments would be anti-dilutive for the loss periods presented.

Basic and diluted net loss per common share for the years ended December 31, 2004, 2003 and 2002 were based on the weighted average number of common shares outstanding during those periods. Options and warrants to purchase CanArgo s Common Stock were outstanding during the years ended December 31, 2004, 2003 and 2002 but were not included in the computation of diluted net loss per common share because the effect of such inclusion would have been anti-dilutive. The total number of such shares excluded from diluted net loss per common share were 14,834,080, 7,986,167 and 6,734,501 for each of the years ended December 31, 2004, 2003 and 2002 respectively.

NOTE 18 INCOME TAXES

CanArgo and its domestic subsidiaries file a U.S. consolidated income tax return. No benefit for U.S. income taxes has been recorded in these consolidated financial statements because of CanArgo s inability to recognize deferred tax assets under provisions of SFAS 109. Due to the implementation of the quasi-reorganization as of October 31, 1988, future reductions of the valuation allowance relating to those deferred tax assets existing at the date of the quasi-reorganization, if any, will be allocated to capital in excess of par value. A reconciliation of the differences between income taxes computed at the U.S. federal statutory rate of 34% and CanArgo s reported provision for income taxes is as follows:

	Year Ended December 31,		
	2004	2003	2002
Income tax benefit at statutory rate	$ (1,617,548)	$ (2,386,000)	$ (1,811,418)
Benefit of losses not recognized	1,617,548	2,386,000	1,811,418
Provision for income taxes	$	$	$
Effective tax rate	0%	0%	0%

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 18 INCOME TAXES (Continued)

The components of deferred tax assets consisted of the following as of December 31:

	2004	2003
Net operating loss carryforwards	$ 10,957,000	$ 8,443,000
Foreign net operating loss carryforwards	3,573,000	5,953,000
Net timing differences on impairments and accelerated capital allowances	9,383,000	9,383,000
	23,913,000	23,779,000
Valuation allowance	(23,913,000)	(23,779,000)
Net deferred tax asset recognized in balance sheet	$	$

On August 1, 1991, August 17, 1994, July 15, 1998 and June 28, 2000, CanArgo experienced changes in ownership as defined in Section 382 of the Internal Revenue Code (IRC). The effect of these changes in ownership is to limit the utilization of certain existing net operating loss carryforwards for income tax purposes to approximately $413,000 per year on a cumulative basis. As of December 31, 2004, total U.S. net operating loss carryforwards were approximately $32,225,000. Of that amount, approximately $21,472,000 was incurred prior to the ownership change in 2000 and is subject to the IRC Section 382 limitation.

The U.S. net operating loss carryforwards expire from 2005 to 2024. CanArgo also has approximately $10,508,000 of foreign net operating loss carryforwards. A significant portion of the foreign net operating loss carryforwards are subject to limitations similar to IRC Section 382.

CanArgo s available net operating loss carryforwards may be used to offset future taxable income, if any, prior to their expiration. CanArgo may experience further limitations on the utilization of net operating loss carryforwards and other tax benefits as a result of additional changes in ownership.

NOTE 19 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 originally in August 2003 and subsequently extended. The total payment received in 2004 was $1,857,000 with the final payment of the consideration received by us in December 2004 at which time we transferred our ownership in CPPL to Westrade Alliance LLC. The gain recorded on disposition of subsidiary was $1,275,351.

The results of discontinued operations in respect of CSOP consisted of the following for the years ending December 31:

	2004	2003	2002
Operating Revenues	$	$ 9,837,445	$ 7,390,138
Income Before Income Taxes and Minority Interest	18,242	392,411	366,556
Income Taxes		(25,297)	(24,132)
Minority Interest in Income		(183,557)	(171,212)
Net Income from Discontinued Operation	$ 18,242	$ 183,557	$ 171,212

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 19 DISCONTINUED OPERATIONS (Continued)

Gross consolidated assets and liabilities in respect of CSOP that are included in assets and liabilities held for sale consisted of the following at December 31:

	2004	2003
Assets held for sale:		
Cash and cash equivalents	$	$ 30,236
Accounts receivable		1,675,317
Inventory		247,758
Other current assets		174,049
Capital assets, net		6,629,450
Investment in other ventures, net		594,484
	$	$ 9,351,294
Liabilities held for sale:		
Accounts payable	$	$ 174,506
Current portion of long term debt		958,346
Income taxes payable		261
Long term debt		2,816,065
	$	$ 3,949,178

During 2003, investments in other ventures included three petrol station sites in Tbilisi, Georgia in which CanArgo had a 50% non-controlling interest. CanArgo accounted for its interest in the three petrol station sites using the equity method and consolidated the remaining sites in which it has controlling interest.

In 2002, the three petrol station sites that CanArgo has a 50% non-controlling interest entered into credit facility agreements amounting to $550,000 with a commercial lender in Georgia. As of December 31, 2003, $261,824 under the facilities were outstanding.

From November 2001 through December 2003, CSOP entered into eight credit facility agreements totaling $5,640,000 with commercial lenders in Georgia and Greece to fund expansion of its petrol station network. As of December 31, 2003, CanArgo had outstanding balances of $3,774,411 related to these credit facilities.

Lateral Vector Resources Inc

Lateral Vector Resources Inc. (LVR), a wholly-owned 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, which reduced the carrying value of LVR to $250,000 as of December 31, 2003. No gain or loss was recorded in 2004 upon the sale of LVR.

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, 2005, we had not received any further payments.

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Notes to Consolidated Financial Statements

NOTE 19 DISCONTINUED OPERATIONS (Continued)

The assets and liabilities of LVR have been classified as Assets held for sale and Liabilities held for sale for the year ended December 31, 2003. The results of operations of LVR have been classified as discontinued for the year ended December 31, 2003 and December 31, 2002.

The results of discontinued operations in respect of LVR consisted of the following for the years ending December 31:

	2004	2003	2002
Income (Loss) Before Income Taxes and Minority Interest		(4,849,036)	(12,735)
Net Income (Loss) from Discontinued Operation	$	$ (4,849,036)	$ (12,735)

Gross consolidated assets in respect of LVR that are included in assets held for sale consisted of the following at December 31:

	2004	2003
Assets held for sale:		
Capital assets, net		250,000
	$	$ 250,000

There were no Gross consolidated liabilities in respect of LVR included in liabilities held for sale at December 31, 2003.

Georgian American Oil Refinery

In 2003, we approved a plan to dispose of our interest in the Georgian American Oil Refinery Limited (GAOR) as the refinery had remained closed since 2001 and neither we nor our partners could find a commercially viable option to putting the refinery back into operation. In February 2004, we 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. The gain recorded on disposition of GAOR was $330,923. 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.

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CANARGO ENERGY CORPORATION
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NOTE 19 DISCONTINUED OPERATIONS (Continued)

The assets and liabilities of GAOR have been classified as Assets held for sale and Liabilities held for sale for the year ended December 31, 2003. The results of operations of GAOR have been classified as discontinued for all periods presented. The minority interest related to GAOR has not been reclassified for any of the periods presented, however net income from discontinued operations is disclosed net of taxes and minority interest. During 2003, a debit balance of $1,274,895 in minority interest was written-off due to a change in the intentions of our minority interest owner and a plan to dispose of the asset. The plan to dispose of the asset also led to the write-off of an inter-company payable relating to oil sales purchased from Ninotsminda Oil Company Limited. These items have been respectively recorded in impairment of other assets and other income (expense) components of continuing operations.

The results of discontinued operations in respect of GAOR consisted of the following for the years ending December 31:

	2004	2003	2002
Operating Revenues	$	$	$ 90,187
Income (Loss) Before Income Taxes and Minority Interest		(1,485,705)	(16,180)
Minority Interest in Loss	(523,968)	(492,951)	7,928
Net Income (Loss) from Discontinued Operation	$ (523,968)	$ (1,978,656)	$ (8,252)

Gross consolidated assets and liabilities in respect of GAOR that are included in assets and liabilities held for sale consisted of the following at December 31:

	2004	2003
Assets held for sale:		
Cash and cash equivalents	$	$ 14,095
Accounts receivable		
Inventory		29,482
Other current assets		13,915
Capital assets, net		100,000
	$	$ 157,492
Liabilities held for sale:		
Accounts payable	$	$ 466,762
	$	$ 466,762

CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 19 DISCONTINUED OPERATIONS (Continued)

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. Following receipt of a non-refundable deposit of $300,000, the unit was shipped to the US for testing. The test was completed at the beginning of 2005 and we expect the generator will be delivered to the buyer in the near future following receipt of the final payment.

The generator has been classified as Assets held for sale for all periods presented. The generator was impaired in 2003 by $80,000 to reflect its fair value less cost to sell. The results for the generator are the following for the years ending December 31:

	2004	2003	2002
Income (Loss) Before Income Taxes and Minority Interest		(80,000)	
Net Income (Loss) from Discontinued Operation	$	$ (80,000)	$

Gross consolidated assets in respect of the generator included in assets held for sale consisted of the following at December 31:

	2004	2003
Assets held for sale:		
Capital assets, net	600,000	587,291
	$ 600,000	$ 587,291

NOTE 20 SEGMENT AND GEOGRAPHICAL DATA

During the year ended December 31, 2004 CanArgo s continuing operations operated through one business segment, oil and gas exploration.

During the year ended December 31, 2004 CanArgo disposed of its downstream activities in Georgia and all operations outside of Georgia. As a result all prior year figures have been restated to conform to the current year presentation and no segment and geographical data is necessary.

In 2004, we sold our oil and gas production in Eastern Europe to thirty five (2003 thirty two, 2002 twenty two) customers. In 2004 sales to three third party customers represented 22%, 21% and 19% of oil and gas revenue respectively. In 2003 sales to three third party customers represented 42%, 32% and 17% of oil and gas revenue respectively. In 2002 sales to four third party customers represented 28%, 26%, 20% and 20% of oil and gas revenue respectively.

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NOTE 21 SUPPLEMENTAL CASH FLOW INFORMATION

The cash paid for interest expense for the years ended December 31, 2004, 2003 and 2002 was $111,559, $35,387and $734 respectively.

There was no cash paid for income taxes for the years ended December 31, 2004, 2003 and 2002.

NOTE 22 STOCK-BASED COMPENSATION PLANS

At December 31, 2004, stock options and warrants had been issued from the following stock based compensation plans:

1995 Long-Term Incentive Plan (1995 Plan). Adopted by the Company in February 1996, this plan allows for up to 7,500,000 shares of the Company s common stock to be issued to officers, directors, employees, consultants and advisors. As of December 31, 2004, 2,931,500 options issued under this plan were outstanding;

Amended and Restated CEI Plan (CAOG Plan). Adopted by the Company following the acquisition by the Company of CanArgo Oil & Gas Inc. in 1998, this plan allowed for 988,000 shares of the Company s common stock to be issued to employees, consultants and advisors. As of December 31, 2004, 525,000 options issued under this plan were outstanding;

Special Stock Options and Warrants. Adopted by the Company in September 2000, this plan was created to allow the Company to retain and provide incentives to existing executive officers and directors and to allow recruitment of new officers and directors following the Company s decision to relocate finance and administrative functions from Calgary, Canada, to London, England. As of December 31, 2004, 1,928,333 special stock options and warrants issued under this plan were outstanding; and

2004 Long Term Stock Incentive Plan (2004 Plan). Adopted by the Company in May 2004, this plan allows for up to 10,000,000 shares of the Company s common stock to be issued to officers, directors, employees, consultants and advisors. As of December 31, 2004, 5,088,000 options issued under this plan were outstanding.

CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 22 STOCK-BASED COMPENSATION PLANS (Continued)

In September and November 2004, CanArgo Energy Corporation issued 5,088,000 new options under the 2004 Long Term Stock Incentive Plan. The exercise price for the issued options is US $0.65 (approximately NOK 4.42) for 5,028,000 issued in September and US $0.95 issued in November, this being at a 10% premium to the trading share price on the date of grant. All these options vested over two years and the options issued in September and November expire on September 23, 2011 and November 23, 2011, respectively. For both issuances, there is an acceleration clause which stipulates that should the holder benefically own 10% of the common stock, then the expiration date is 5 years after the grant date. With regards to individual officers and directors, details of existing and new options are as follows:

	New Options
David Robson	1,500,000
Vincent McDonnell	900,000
Liz Landles	510,000
Michael Ayre	255,000
Russ Hammond	255,000
Nils Trulsvik	255,000

In March 2003, CanArgo Energy Corporation resolved to issue 1,589,166 new options and amend the terms and conditions attaching to 5,117,501 of existing options. The exercise price for the newly issued options is US $0.10 (approximately NOK 0.71) approximately 2.5 times the trading share price on the date of grant. All these options vested immediately and expire on March 4, 2008. With regards to individual officers and directors, details of existing and new options are as follows:

	Amended Terms	New Options	Total
David Robson	2,666,667	333,333	3,000,000
Vincent McDonnell	300,000	300,000	600,000
Russ Hammond	346,250	153,750	500,000
Nils Trulsvik	346,250	153,750	500,000
Liz Landles	172,000	28,000	200,000

The purpose of the Company s stock option plans is to further the interest of the Company by enabling officers, directors, employees, consultants and advisors of the Company to acquire an interest in the Company by ownership of its stock through the exercise of stock options and stock appreciation rights granted under its various stock option plans.

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 22 STOCK-BASED COMPENSATION PLANS (Continued)

A summary of the status of stock options granted under the 1995 Plan, CAOG Plan and special stock options and warrants is as follows:

	Shares Available for Issue	Shares Issuable Under Outstanding Options	Weighted Average Exercise Price
Balance, December 31, 2001	2,111,335	7,092,001	0.92
Options (1995 Plan):			
Increase in shares available for issue Granted at market	(130,000)	130,000	0.14
Exercised			
Expired	307,500	(307,500)	0.25
CAOG Plan Authorization:			
Granted at market			
Exercised			
Expired	180,000	(180,000)	1.11
Balance, December 31, 2002	2,468,835	6,734,501	0.93
Options (1995 Plan):			
Increase in shares available for issue Granted at market	(1,291,833)	1,291,833	0.10
Exercised			
Expired	132,500	(132,500)	1.35
CAOG Plan Authorization:			
Granted at market	(297,333)	297,333	0.10
Exercised			
Expired	205,000	(205,000)	1.19
Balance, December 31, 2003	1,217,169	7,986,167	0.26

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 22 STOCK-BASED COMPENSATION PLANS (Continued)

	Shares Available for Issue	Shares Issuable Under Outstanding Options	Weighted Average Exercise Price

Shares issuable upon exercise of vested options and the corresponding weighted average exercise price are as follows:

	Shares Issuable Under Exercisable Options	Weighted Average Exercise Price
December 31, 2002	5,114,834	$ 0.93
December 31, 2003	7,337,167	$ 0.23
December 31, 2004	6,480,833	$ 0.49

The weighted average fair value of options granted during the year was $0.66, $0.10 and $0.14 for the years ended December 31, 2004, 2003 and 2002 respectively.

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 22 STOCK-BASED COMPENSATION PLANS (Continued)

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

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Options Outstanding at December 31, 2004	Weighted Average Remaining Term	Weighted Average Exercise Price	Number Of Options Exercisable at December 31, 2004	Weighted Average Exercise Price
$0.10 to $0.14	3,265,833	3.17	0.10	3,265,833	0.10
$0.15 to $0.69	6,012,000	6.60	0.85	2,080,000	0.65
$0.70 to $1.44	1,195,000	1.56	1.32	1,155,000	1.33
$0.10 to $0.44	10,472,833	4.96	0.55	6,480,833	0.49

As further discussed in Note 2, Summary of Significant Accounting Policies, Stock-Based Compensation Plans, in August 2003, the Company adopted SFAS No. 123 *Accounting For Stock-Based Compensation*, as of January 1, 2003. The Company has elected to utilize the prospective method of transitioning from the intrinsic value to the fair value method of accounting for stock-based compensation. This change decreased 2003 net income by approximately $276,507. Stock based awards in existence prior to 2003 will continue to be accounted for under APB Opinion No. 25, Accounting for Stock Issued to Employees, unless they are re-priced or modified.

Stock based compensation costs are amortized on a straight line basis over the vesting period.

NOTE 23 RELATED PARTY TRANSACTIONS

Of the 50% of CanArgo Standard Oil Products Limited not held by CanArgo prior to its disposal in December, 2004, 41.65% was held by Standard Oil Products, an unrelated third party entity, and 8.35% held by an individual, Mr Levan Pkhakadze, who is one of the founders of Standard Oil Products and is an officer and director of CanArgo Standard Oil Products. The majority of refined product purchased by CanArgo Standard Oil Products for resale at its petrol stations is purchased from a company controlled by Standard Oil Products who together with and an individual shareholder, own the 50% interest in CanArgo Standard Oil Products not held by CanArgo. Total product purchases from the related company in 2002 were $5,263,000.

Certain equipment is provided to Georgian British Oil Company Ninotsminda by a company owned by significant employees of Georgian British Oil Company Ninotsminda. Total rental payments for this equipment in 2004 were $107,946 and $183,428 in 2003. In 2003, the same company provided additional services to Georgian British Oil Company Ninotsminda in accordance with the farm-in agreement in respect of the Manavi well for the value of

$450,000.

CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 23 RELATED PARTY TRANSACTIONS (Continued)

Vazon Energy is a company solely owned by Dr. Robson. A management services agreement exists between CanArgo Energy Corporation and Vazon Energy whereby the services of Dr. Robson, Mrs. Landles and Mr. Moroney are provided to CanArgo.

J.F. Russell Hammond, a non-executive director of CanArgo, is also an investment advisor to Provincial Securities who became a minority shareholder in the Norio PSA through a farm-in agreement to the Norio MK72 well. On September 4, 2003, co-incident with the Georgian Oil farm-in to the Norio PSA, Provincial Securities was given 2,273,523 shares of CanArgo common stock in exchange for his interest in the Norio PSA (see Note 13).

Transactions with affiliates are reviewed and voted on solely by non-interested directors.

NOTE 24 SUBSEQUENT EVENTS

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 Company s common stock issued pursuant to the takedown under the Equity Line completed on February 21, 2005 the proceeds of which should have been credited to the Company under its 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 $532,548 were used to reduce the promissory note to Cornell Capital from $500,000 to $0 and pay accrued interest.

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 $569,500 to CanArgo.

As at March 14, 2005 we have 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.

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NOTE 25 QUARTERLY FINANCIAL DATA (Unaudited)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Operating revenue from continuing operations	$,3,360,471	$ 2,078,553	$ 2,007,838	$ 2,127,658
Operating income (Loss) from continuing operations	974,195	(992,604)	(1,401,093)	(1,534,698)
Net income (loss) from continuing operations	1,032,016	(1,405,230)	(2,644,174)	(1,834,860)
Net income (loss) from discontinued operations, net of taxes and minority Interest	490,364	(43,539)	95,384	
Cumulative effect of change in accounting policy				
Net income (loss)	1,522,380	(1,448,769)	(2,548,790)	(1,834,860)
Comprehensive income (loss)	1,984,516	(1,691,382)	(2,458,082)	(1,998,628)
Net income (loss) per common share - basic and diluted from continuing operations	0.01	(0.01)	(0.02)	(0.01)
Net income (loss) per common share - basic and diluted from discontinued operations				
Net income (loss) per common share - basic and diluted	0.01	(0.01)	(0.02)	(0.01)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Operating revenue from continuing operations	$ 1,141,458	$ 1,859,995	$ 2,494,029	$ 2,609,298
Operating income (Loss) from continuing operations	(953,127)	(144,707)	274,880	35,395
Net income (loss) from continuing operations	(941,322)	(130,668)	270,939	(120,881)
Net income (loss) from discontinued operations, net of taxes and minority Interest	(7,038)	26,940	42,779	(6,682,756)
Cumulative effect of change in accounting policy	41,290			
Net income (loss)	(907,070)	(103,728)	313,718	(6,803,638)
Comprehensive income (loss)	(876,905)	(157,974)	325,529	(6,942,499)
Net loss per common share - basic and diluted from continuing operations	(0.01)			
Net loss per common share - basic and diluted from discontinued operations				(0.06)
Net loss per common share - basic and diluted	(0.01)			(0.06)

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 26 SUPPLEMENTAL OIL AND GAS DISCLOSURE (Unaudited) (Continued)

ESTIMATED NET QUANTITIES OF OIL AND GAS RESERVES

Users of this information should be aware that the process of estimating quantities of proved and proved developed natural gas and crude oil reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved reserves are estimated quantities of natural gas, crude oil and condensate that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs with existing equipment under existing economic and operating conditions.

Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and under existing economic and operating conditions.

No major discovery or other favorable or adverse event subsequent to December 31, 2004 is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

The following tables set forth our net proved oil and gas reserves, including the changes therein, and net proved developed reserves at December 31, 2004, as estimated by the independent petroleum engineering firm, Oilfield Production Consultants Limited:

Net Proved Developed and Undeveloped Reserves Oil (In Thousands of Barrels) Republic of Georgia

	2004	2003	2002
January 1	4,395	2,901	3,729
Purchase of properties			
Revisions of previous estimates	(76)	1,951	(630)
Extension, discoveries, other additions			
Production	(243)	(457)	(198)
Disposition of properties			
December 31	4,076	4,395	2,901

Net Proved Developed Oil Reserves December 31, 2004	2,122

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 26 SUPPLEMENTAL OIL AND GAS DISCLOSURE (Unaudited) (Continued)

Net Proved Developed and Undeveloped Reserves Gas (In Million Cubic Feet) Republic of Georgia

	2004	2003	2002
January 1	1,941	2,414	5,025
Purchase of properties			
Revisions of previous estimates	(66)	(197)	(2,265)
Extension, discoveries, other additions			
Production	(172)	(276)	(346)
Disposition of properties			
December 31	1,703	1,941	2,414

Net Proved Developed Oil Reserves December 31, 2003	950

Net proved oil reserves in the Republic of Georgia consisted of the following at December 31:

	2004		2003	
	Oil Reserves Gross (MSTB)	PSC Entitlement Volumes (MSTB) (1)	Oil Reserves Gross (MSTB)	PSC Entitlement Volumes (MSTB) (1)
Proved Developed Producing	3,264	2,122	3,593	2,336
Proved Undeveloped	3,007	1,954	3,169	2,059
Total Proven	6,271	4,076	6,762	4,395

Net proved gas reserves in the Republic of Georgia consisted of the following at December 31:

	2004		2003	
	Gas Reserves Gross (MMCF)	PSC Entitlement Volumes	Gas Reserves Gross (MMCF)	PSC Entitlement Volumes

		(MMCF) (1)		(MMCF) (1)
Proved Developed Producing	1,462	950	1,742	1,133
Proved Undeveloped	1,158	753	1,243	808
Total Proven	2,620	1,703	2,985	1,941

(1) PSC Entitlement Volumes attributed to CanArgo are calculated using the economic interest method applied to the terms of the production sharing contract. PSC Entitlement Volumes are those produced volumes which, through the production sharing contract, accrue to the benefit of Ninotsminda Oil Company after deduction of Georgian Oil s share which includes all Georgian taxes, levies and duties. As a result of CanArgo s interest in Ninotsminda Oil Company, these volumes accrue to the benefit of CanArgo for the recovery of capital, repayment of operating costs and share of profit.

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 26 SUPPLEMENTAL OIL AND GAS DISCLOSURE (Unaudited) (Continued)

Results of operations for oil and gas producing activities for 2004, 2003 and 2002 are as follows:

Year Ended December 31, 2004	Republic of Georgia
Revenues	$ 9,574,520
Operating expenses	2,320,756
Depreciation, depletion and amortization	2,298,218
Operating Income (Loss)	4,955,546
Income tax provision	
Results of Operations for Oil and Gas Producing Activities	$ 4,955,546

Year Ended December 31, 2003	Republic of Georgia
Revenues	$ 7,882,870
Operating expenses	1,051,905
Depreciation, depletion and amortization	2,634,459
Operating Income (Loss)	4,196,506
Income tax provision	
Results of Operations for Oil and Gas Producing Activities	$ 4,196,506

Year Ended December 31, 2002	Republic of Georgia
Revenues	$ 4,179,208
Operating expenses	1,537,917
Depreciation, depletion and amortization	3,353,266
Operating Income (Loss)	(711,975)
Income tax provision	

Results of Operations for Oil and Gas Producing Activities	$ (711,975)

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 26 SUPPLEMENTAL OIL AND GAS DISCLOSURE (Unaudited) (Continued)

Costs incurred for oil and gas property acquisition, exploration and development activities for 2004, 2003 and 2002 are as follows:

Year Ended December 31, 2004	Eastern Europe
Property Acquisition	
Unproved*	$ 3,416,900
Proved	3,880,000
Exploration	1,757,010
Development	6,588,137
Total costs incurred	$ 15,642,047

Year Ended December 31, 2003	Eastern Europe
Property Acquisition	
Unproved*	$
Proved	
Exploration	(329,998)
Development	5,200,614
Total costs incurred	$ 4,870,616

Year Ended December 31, 2002	Eastern Europe
Property Acquisition	
Unproved*	$
Proved	
Exploration	12,167,238
Development	543,280
Total costs incurred	$ 12,710,518

* These amounts represent costs incurred by CanArgo and excluded from the amortization base until proved reserves are established or impairment is determined.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

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

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 26 SUPPLEMENTAL OIL AND GAS DISCLOSURE (Unaudited) (Continued)

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

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

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

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

December 31, 2004 (in thousands)	Republic of Georgia
Future cash inflows	$ 112,894
Less related future:	
Production costs	27,643
Development and abandonment costs	10,200
Future net cash flows before income taxes	75,051
Future income taxes(1)	(38)
Future net cash flows	75,013
10% annual discount for estimating timing of cash flows	28,601
Standardized measure of discounted future net cash flows	$ 46,412

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 26 SUPPLEMENTAL OIL AND GAS DISCLOSURE (Unaudited) (Continued)

December 31, 2003 (in thousands)	Republic of Georgia
Future cash inflows	$ 90,674
Less related future:	
Production cots	24,621
Development and abandonment costs	6,407
Future net cash flows before income taxes	59,646
Future income taxes(1)	(1,596)
Future net cash flows	58,050
10% annual discount for estimating timing of cash flows	20,520
Standardized measure of discounted future net cash flows	$ 37,530

(1) Future cash flows are based on PSC Entitlement Volumes attributed to CanArgo using the economic interest method applied to the terms of the production sharing contract. PSC Entitlement Volumes are those produced volumes which, through the production sharing contract, accrue to the benefit of Ninotsminda Oil Company Limited after deduction of Georgian Oil s share which includes all Georgian taxes, levies and duties. As a result of our interest in Ninotsminda Oil Company Limited, these volumes accrue to the benefit of CanArgo for the recovery of capital, repayment of operating costs and share of profit.

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

	December 31		
In Thousands	2004	2003	2002
Beginning of year	$ 37,530	$ 14,107	$ 16,695
Purchase (sale) of reserves in place			
Revisions of previous estimates	(4,251)	24,576	(6,978)
Development costs incurred during the period	6,588	324	543
Additions to proved reserves resulting from extensions, discoveries and improved Recovery			
Accretion of discount	1		
Sales of oil and gas, net of production costs	(6,004)	(6,829)	(2,625)

Net change in sales prices, net of production costs	18,057	8,317	4,990
Changes in production rates (timing) and other	(5,510)	(2,965)	1,482
Net increase (decrease)	8,881	23,423	(2,588)
End of year	$ 46,411	$ 37,530	$ 14,107

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CANARGO ENERGY CORPORATION
Notes to Consolidated Financial Statements

NOTE 26 SUPPLEMENTAL OIL AND GAS DISCLOSURE (Unaudited) (Continued)

Capitalized costs relating to Oil and Gas Producing Activities is as follows:

December 31, 2004 (in thousands)	Republic of Georgia
Proved	$ 61,458
Unproved	25,103
Total capitalized Costs	85,561
Accumulated depreciation, depletion and amortization	(23,382)
Net capitalized costs	$ 63,179

December 31, 2003 (in thousands)	Republic of Georgia
Proved	$ 44,327
Unproved	25,938
Total capitalized Costs	70,265
Accumulated depreciation, depletion and amortization	(21,084)
Net capitalized costs	$ 49,181