CANADA SOUTHERN PETROLEUM LTD.

ANNUAL INFORMATION FORM

Year Ended
December 31, 2004

March 28, 2005

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DEFINITIONS

In this Annual Information Form, the following words and phrases have the meanings set forth below, unless the context otherwise requires:

"**AIF**" means the Annual Information Form of the Company dated March 28, 2005;

"**Common Share**" means a common share in the capital of the Company;

"**Company**", "**Corporation**" or "**Canada Southern**" means Canada Southern Petroleum Ltd., a corporation continued under the laws of the Province of Alberta;

"**Crown**" means Her Majesty the Queen in Right of Canada or a Province thereof;

"**crude oil**" or "**oil**" means a mixture, consisting mainly of pentanes and heavier hydrocarbons that may contain sulphur compounds, that is liquid at the conditions under which its volume is measured or estimated, but excluding such liquids obtained from the processing of natural gas;

"**GLJ**" means Gilbert Laustsen Jung Associates Ltd., independent petroleum consultants, Calgary, Alberta;

"**GLJ Report**" means the report dated March 17, 2005, prepared by GLJ evaluating the Company's petroleum and natural gas reserves as of December 31, 2004;

"**gross acres**" means the total number of acres in which the Company has an interest;

"**gross wells**" means the total number of wells in which we have a working interest;

"**natural gas**" means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions is essentially a gas, but which may contain liquids. Natural gas reserve estimates are reported on a marketable basis, that is gas which is available to a transmission line after removal of certain hydrocarbons and non-hydrocarbon compounds present in the raw natural gas and which meets specifications for use as a domestic, commercial or industrial fuel;

"**natural gas liquids**" or "**NGL**" means those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants or recovered from field separators, scrubbers of other gathering facilities. These liquids include the hydrocarbon components ethane, propane, butanes and pentanes plus, or a combination thereof;

"**net acres**" means gross acres multiplied by the Company's percentage working interest therein;

"**net carried interest wells**" are determined on an "after conversion to working interest" basis, as until payout is reached we are not entitled to any cash flows from the property

"**net wells**" means the aggregate of the percentage working interest of each of the gross wells;

"**SWS**" means the Second White Specks Formation; and

"**working interest**" means the net interest held by us in an oil and natural gas property which normally bears its proportionate share of the costs of exploration, development and operation as well as any royalties or other production burdens.

All dollar amounts set forth in this AIF are in Canadian dollars, except where otherwise indicated.

ABBREVIATIONS

The following abbreviations are used in this AIF to represent the following terms:

"API"	means the American Petroleum Institute;
"API gravity"	means the method of expressing the specific gravity of crude oil in degrees;
"bbl"	means barrel;
"bbls"	means barrels;
"bbl/d"	means barrels per day;
"bcf"	means billion cubic feet;
"boe"	means barrels of oil equivalent, with natural gas converted at 6 mcf per barrel of oil equivalent (6:1) unless otherwise stated;
"boe/d"	means barrels of oil equivalent per day;
"mbbls"	means 1,000 barrels;
"mboe"	means 1,000 boe;
"Mmboe"	means 1,000,000 boe;
"mcf"	means 1,000 cubic feet;
"mcf/d"	means 1,000 cubic feet per day;
"mmbtu"	means 1,000,000 British thermal units;
"mmcf"	means 1,000,000 cubic feet;
"mmcf/d"	means 1,000,000 cubic feet per day;
"NGL"	means natural gas liquids; and
"WTI"	means West Texas Intermediate crude oil delivered at Cushing, Oklahoma.

FORWARD-LOOKING INFORMATION

This document contains certain forward-looking statements relating, but not limited, to operations, financial performance, business prospects and strategies of the Company. Forward-looking information typically contains statements with words such as "anticipate", "believe", "expect", "plan", "intend" or similar words suggesting future outcomes or statements regarding an outlook on, without limitation, commodity prices, estimates of future production, the estimated amounts and timing of capital expenditures, anticipated future debt levels and royalty rates, or other expectations, beliefs, plans, objectives, assumptions or statements about future events or performance.

Shareholders are cautioned not to place undue reliance on forward-looking information. By its nature, forward-looking information of the Company involves numerous assumptions, inherent risks and uncertainties both general and specific that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur. These factors include, but are not limited to: the pricing of natural gas and oil; the effects of competition and pricing pressures; risks and uncertainties involving the geology of natural gas and oil; operational risks in exploring for, developing and producing natural gas and oil; the uncertainty of estimates and projections relating to production, costs and expenses; the significant costs associated with the exploration and development of the properties on which the Company has interests, particularly the Kotaneelee field; shifts in market demands; risks inherent in the Company's marketing operations; industry overcapacity; the strength of the Canadian economy in general; currency and interest rate fluctuations; general global and economic and business conditions; changes in business strategies; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserves estimates; various events which could disrupt operations, including severe weather conditions, technological changes, our anticipation of and success in managing the above risks; potential increases in maintenance expenditures; changes in laws and regulations, including trade, fiscal, environmental and regulatory laws; and health, safety and environmental risks that may affect projected reserves and resources and anticipated earnings or assets. See also the information set forth under the heading "Information Concerning the Oil and Natural Gas Industry". Statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future.

We caution that the foregoing list of important factors is not exhaustive. We undertake no obligation to update publicly or revise the forward-looking information provided in this document, whether as a result of new information, future events or otherwise, or the foregoing list of factors affecting this information.

THE COMPANY

Name, Address and Incorporation

The Corporation was incorporated under the *Companies Act* (Canada) in 1954. It was continued under the *Nova Scotia Companies Act* in 1980 and continued under the *Business Corporations Act (*Alberta) on March 2, 2005. The Corporation's head office and principal place of business is Suite 250, 706 - 7th Avenue S.W., Calgary, AB T2P 0Z1.

Intercorporate Relationships

The Corporation has two wholly owned subsidiaries; Canpet Inc. and CS Petroleum Ltd. both of which are currently inactive.

GENERAL DEVELOPMENT OF THE BUSINESS

General

We are engaged in the exploration for and development of properties containing or believed to contain recoverable natural gas and oil reserves and the sale of natural gas and oil from these properties. Although many of the properties in which we have interests are undeveloped, all properties with proved reserves are partially or fully developed. Our interests in exploratory ventures are on properties located in Alberta, British Columbia, Saskatchewan, the Northwest and Yukon Territories and the Arctic Islands in Canada. Our principal asset is our 30.67% working interest in the Kotaneelee field, a producing natural gas field in the Yukon Territory. We also have interests in producing properties in British Columbia.

Year ended December 31, 2002

Our activity during the year ended December 31, 2002 and for many years prior, was focused on the Kotaneelee litigation. We were plaintiffs in a litigation against some of the larger oil and gas companies in the world. The litigation dealt with complex issues that took an extended period of time to be dealt with through the court system. In order to meet the high costs of the litigation over this period of time, we sold certain of our oil and gas properties and raised equity to generate sufficient cash to continue the process. Had the Company run out of cash resources to continue, the litigation would have had to be abandoned. As a result, our oil and gas exploration and development activity during much of that period was limited.

Year ended December 31, 2003

In early 2002, the Company determined that, when considering all of the relevant risks involved, we should pursue a settlement on the Kotaneelee litigation. On September 9, 2003, the parties in the litigation concerning the Kotaneelee gas field entered into a comprehensive Settlement Agreement.. The settlement was finalized on October 3, 2003. Pursuant to the settlement there has been a complete abandonment of the litigation, including the claim that the defendants failed to fully develop the field.

In the third quarter of 2003, we realized a gross pre income tax amount of $23.727 million in the settlement, which amount represents a complete settlement of the litigation, including a recovery of the wrongfully withheld gas processing fees and related interest. These proceeds constituted taxable income for Canadian income tax purposes upon receipt by the Company.

In connection with the settlement, we acquired on October 31, 2003, from Perkins Holdings, Ltd. and Levcor International Inc. a 0.67% carried interest in the Kotaneelee field formerly held by Levcor, including the associated interest in the litigation.

Also in connection with the settlement, we agreed to be responsible for our share of abandonment and reclamation liabilities at the Kotaneelee field when they occur. It is estimated that our share of the abandonment liabilities will amount to approximately $2.4 million (undiscounted).

The settlement agreement does not include any understandings with or commitments by the working interest owners to further develop the Kotaneelee field beyond those mechanisms for doing so contained in the joint venture agreements.

As a result of settlement, we could for the first time in many years shift our focus toward the oil and gas business.

Year ended December 31, 2004

In 1991 and 1997, the Company granted contingent interests in certain net recoveries from the Kotaneelee litigation. After the settlement with the defendants was agreed upon, our Board of Directors established a committee comprised solely of directors with no direct or indirect personal interest in the matter of the contingent interests. This independent committee of directors, comprised of Messrs. Kanik, McGinity and Stewart, consulted with independent outside counsel with regard to what amounts, if any, were payable pursuant to the contingent interests. During the fourth quarter of 2003, counsel to the independent committee advised each of the contingent interest grantees that the committee had concluded, based on advice of counsel, that there was no entitlement arising under such interests.

During the first quarter of 2004, in order to avoid a potentially prolonged, expensive and distracting litigation, we reached an agreement for an all-inclusive settlement with certain parties, including a former director and former litigation counsel to the Company, who were asserting claims of entitlement against the Company's net recoveries in the Kotaneelee litigation. Under the terms of the settlement, which had been accrued in our fourth quarter 2003 financial results, we paid these parties a total of $1 million in return for a general release from the parties asserting the claims and an agreement by us not to seek an adjustment in the prior payments for professional services made to prior litigation counsel.

During the second quarter we converted our Kotaneelee property from a carried interest to a working interest. The conversion to a working interest at Kotaneelee represents a decision by us toward direct management of our oil and gas assets.

During the third quarter of 2004, we settled with certain former-employee contingent interest holders for $48,000.

During the fall of 2004 the Kotaneelee L-38 development well commenced drilling. This was the first well to be drilled on one of the Kotaneelee leases for over 20 years. We participated in the costs for our full 30.67% interest.

DESCRIPTION OF THE BUSINESS

Principal Producing Properties

Yukon Territory - The Kotaneelee Field

Our principal asset is our 30.67% working interest in the Kotaneelee gas field in the Yukon Territory, Canada, held pursuant to 5 leases for a 21 year term, which expire on May 16, 2010. Unproductive acreage may expire at the end of the lease term. We have held an interest in the 30,260 gross acres continuously since 1957.

Canada Southern discovered the natural gas field in 1963 with the drilling of well "I-27."

Seven wells have been drilled on the property: two producing natural gas wells, one salt water disposal well, three abandoned wells, and one that finished drilling in March 2005 and has recently been completed. Of the three abandoned wells, two were abandoned due to down-hole mechanical problems. The length of drilling time for these wells (from spud to rig release date) ranged from 198 to 526 days.

The two productive wells ("B-38" and "I-48") are producing from the Nahanni Formation. This formation is located approximately 12,000 feet below the surface and is characterized as being a low porosity, low permeability carbonate. The prolific production is the result of a complex system of fractures within the reservoir. The B-38 well was drilled in 1977 (drilling time of 198 days) and penetrated 234 feet of net pay. The I-48 well, drilled in 1980 (drilling time of 358 days), encountered 470 feet of net gas pay. The most recent well drilled (L-38) was drilled in 2004/2005. The L-38 well was completed in late March 2005, and is currently awaiting tie-in and testing to determine whether or not the well will be commercially successful.

Pursuant to 1966 and 1977 agreements, we converted our interest into the carried interest position that we held until May 1, 2004, at which time we converted it to a 30.67% working interest. As a carried interest owner, we were entitled to receive our net share of field revenues after the working interest owners recovered all of their capital and operating costs (i.e., upon the field reaching payout).

On January 19, 2001, our carried interest account in the Kotaneelee field reached payout status. During the second quarter of 2001, we began receiving our share of net proceeds from the field and accordingly commenced reporting our share of revenues.

Although the Kotaneelee field sporadically produced a total of 1.6 bcf of natural gas over 10 months between 1979 and 1981, continuous production commenced in February 1991. According to government reports, gross yearly gas and water production from the Kotaneelee natural gas field since 1991 has been as follows:

Calendar Year	**Natural Gas Production (bcf)**	**Water Production (mbbls)**
1991	8.1	43
1992	18.0	90
1993	17.5	89
1994	16.7	90
1995	15.7	90
1996	15.2	85
1997	14.4	84
1998	16.0	98
1999	22.3	148
2000	20.2	143
2001	16.9	206
2002	13.1	370
2003	9.1	530
2004	6.6	696
Total	209.8	2,762

The gross production from the field for the month of December 2004 was approximately 15.3 mmcf /d (4.8 mmcf/d from B-38 and 10.5 mmcf/d from I-48). Gross natural gas sales from both wells were approximately 11.9 mmcf/d for the month of December 2004.

Natural gas sales from the Kotaneelee field are approximately 78% of total monthly production due to shrinkage and fuel gas requirements.

Water production has increased since 2001. The operator improved the water handling capabilities of the surface equipment during the first quarter of 2002. Water production continues to increase and water handling capacity continues to be a concern. Natural gas production continues to decline as the reservoir pressure declines. Water production will at some point become a constraining factor on gas production. We are not able to predict with certainty the remaining economic life of the existing producing wells, their associated production profiles and the extent to which these wells will be able to access proven developed reserves.

Gross water production from each Kotaneelee well for the month of December 2004 was 1,413 bbl/d from the B-38 well and 763 bbl/d from the I-48 well (water production in December 2003 – B-38 was 1,427 bbl/d and the I-48 was 161 bbl/d).

In an effort to extend the remaining life of the B-38 well, during the spring of 2005, the operator is installing a siphon string in order to improve the lifting of the increasing amount of water. We are participating to the extent of our working interest in the operation. As the project is not yet complete, we do not know if, or to the degree of which, it will be successful in extending the economic life of the well.

Because of uncertainties as to production rates, natural gas prices and future capital expenditures, we were unable to accurately predict the amount of future net proceeds that we might have received from the field.

Current/Future Development of Kotaneelee

Subsequent to the settlement of the litigation the prospect of future development became a reality. In September 2003 the working interest partners shot 23.6 km (14.7 miles) of 2-D seismic. In December 2003, costs associated with the acquisition of this seismic data were charged to the carried interest account and we received this data in January 2004. Upon receipt of this seismic data, we retained external geological, geophysical and engineering consultants for the task of re-evaluating the field's exploration and development potential. This re-evaluation included, among other things, reprocessing certain of the previously shot seismic data (previously all in its original form) in an attempt to enhance data quality through modern data processing technologies. This re-evaluation was completed in early May 2004.

Effective May 1, 2004, we converted from a 30.67% carried interest in the Kotaneelee mineral leases and related assets to a 30.67% working interest.

On May 3, 2004, we were served by the field operator with a notice to commence drilling the L-38 development well in the third quarter of 2004.

Based in part on our reprocessing and reinterpretation of our 2-D geophysical data, we elected to participate to our full 30.67% working interest in the L-38 well.

This well commenced drilling on August 22, 2004. The notice from the operator to drill and case the proposed well included an estimated gross cost of $16.7 million, of which our share was to be approximately $5.1 million. The well reached total depth on March 10, 2005 and due to the technical and drilling challenges experienced by the operator, gross drilling costs are estimated to be $29.5 million ($9.0 million net to us). The L-38 well was completed in late March 2005 with estimated gross completion costs of $4.9 million ($1.5 million our share). As part of the completion operation, the well was flowed for a short period of time. However, due to the warm weather in the area and the rapidly deteriorating ice bridges, the decision was made to suspend the flow and remove the drilling rig and test equipment to avoid paying standby charges. Otherwise, the equipment would need to remain on location until approximately June when the river is open for barging operations.

While there is natural gas present, there is currently insufficient information to estimate expected flow rates or to estimate recoverable proven reserves.

Testing will be performed after the well is tied in during the second quarter of 2005. Additional gross costs of $4.6 million ($1.4 million our share) are expected to be incurred for surface equipment and tie-in of the well for production. Total costs for the project are estimated to be $39 million ($11.9 million our share), of which approximately 50% was incurred prior to year end and reflected in the financial statements for the year ended December 31, 2004.

We agreed with the operator's decision to remove the drilling and testing equipment, and to incur the cost and risk of tying in prior to testing. However, readers are cautioned that presently we do not have sufficient information to determine whether or not the well will be commercially successful.

At this time we are not aware of, and do not expect, further drilling to occur in the Kotaneelee area in the near future. We believe that any such decision would only be considered subsequent to the receipt of positive production information from the L-38 well and a complete re-evaluation of our existing 2-D seismic data, or acquisition of new seismic data, in the area. Notwithstanding the results of the geophysical interpretation it is only through the drilling of additional wells that definitive information of this complex area can be obtained.

Risk Factors in Future Development of the Kotaneelee Field

Should additional drilling at Kotaneelee be considered in the future, our consideration of the risks factors involved would be evaluated carefully. The Kotaneelee field historically has been a significant natural gas producer. When, or if, future wells are drilled on the property, and whether new wells will tap additional economic reserves, is uncertain. Investors are cautioned that further exploration and development of this block also comes at a significant capital cost and with significant risks. For a further discussion of risk factors please see the section entitled "Risk Factors" at page 28 below. Certain of these risks are as follows:

Geophysical risk:
This is a very complicated area in which to perform a geophysical interpretation. Shooting seismic is difficult due to the rugged mountainous terrain of the area. The existing seismic inventory is of varying vintage and quality, further complicating the interpretation. With only seven wells drilled over the entire 30,260 acres, in an area known to have significant faulting, thrusting and fracturing, it is difficult to correlate geophysical data between wells and arrive at a totally conclusive interpretation. As such, any seismic interpretation is at risk of being inaccurate.

Geological risk:
The Nahanni Formation, the producing geologic zone at Kotaneelee, is very complex. A new well could encounter the structure, but be drilled in an area where the fracture system believed to assist in natural gas production might not be present.

Production risk:
Assuming that a commercial reservoir of natural gas is encountered, and that a well is placed on production, the risk of water interfering with the operation of the well may prevent the production of a portion of the gas reserves in place. In all natural gas and oil fields, producers do not expect to recover all of the hydrocarbons in place.

Cost risk:
Factors such as subsurface faulting, thrusting and fracturing could result in significantly longer drilling times than budgeted. Additional drilling time typically equates to additional costs, which could be significant.

Future Yukon Land Sales

The Yukon covers 483,450 square km (186,660 square miles) where a total of only 72 wells have been drilled to date. We currently have interests in the only two producing gas wells in the Yukon. The Yukon Government assumed responsibility for its oil and gas resources in 1998 and has established a regime which is intended to facilitate and promote new oil and gas exploration and development. To achieve that goal, the Yukon Government is in the process of attempting to settle several native land claims prior to granting mineral leases for the exploration of natural gas and oil. Although the Yukon Government has achieved significant success in resolving these land claim disputes, settlement on lands surrounding Kotaneelee has yet to occur. Once these land claims have been settled, we understand that the Yukon Government intends to offer for sale the Petroleum and Natural Gas ("P&NG") rights on acreage surrounding the Kotaneelee field. Given the production from the Kotaneelee field, we expect competition to be intense for control of this exploratory acreage.

British Columbia - Properties

Prior to the Kotaneelee field reaching undisputed payout status, our principal source of income had been from the sale of natural gas and associated liquids from properties located in northeast British Columbia. Effective January 1, 2001, we converted our carried interests in northeast British Columbia (including the areas of Buick Creek, Wargen, Clarke Lake, and Ekwan) to working interests. Effective April 1, 2001, we converted our carried interest in the Siphon area to a working interest. We converted to working interest positions in an attempt to gain greater control of these assets.

Conversion issues

The conversion from carried to working interest at Buick Creek, Siphon and Wargen created an issue with respect to facility ownership. When development of these properties occurred, the operators charged certain facility and pipeline infrastructure construction costs to the carried interest account. As a result of payout and conversion, we have paid for and therefore believe we should be recognized as an owner of these facilities. Ownership interest in facilities has both strategic and economic benefits.

Commencing in 2001, we approached the current operators to discuss our ownership rights in the Siphon, Buick Creek and Wargen facilities.

Subsequent to these discussions, we became recognized as a 22.5% owner of the Siphon and Buick Creek facilities on April 7, 2003 and June 27, 2003, respectively. Discussions with the operator at Wargen are ongoing and are expected to be completed later in 2005.

Withheld revenue issue

In 2000, the operator of the carried interest properties at Buick Creek, Wargen and Clarke Lake in British Columbia withheld approximately $1 million in payments from the carried interest account to recover an amount claimed to have been overpaid to us in prior years. We disagreed with the operator's position.

On April 6, 2004, in full settlement of this issue, we received $300,000. In connection with the settlement, we were also recognized as an owner of certain items that were previously charged to the carried interest account. We became recognized as a proprietary owner, and received copies of, approximately 183 km (114 miles) of 2-D seismic data in the areas of Buick Creek, Wargen and Peejay of N.E. British Columbia. We also became recognized as an 11.5% working interest owner in the pooled salt water disposal facilities at Clarke Lake.

Further in connection with the settlement, we expended $131,000 to acquire an interest in the pipeline infrastructure at Clarke Lake, and paid salt water disposal operating costs of $6,000 for the period from January 7, 2001 to December 31, 2003.

Siphon

We hold 10,235 gross (5,391 net) acres of certain mineral rights for an average 53% working interest at Siphon. We have owned our interest in certain of these lands since the early 1950's. We were formally recognized as a 22.5% working interest owner of the Siphon facilities on April 7, 2003.

In 2004, our share of sales averaged 362 mcf/d of natural gas and 4 bbl/d of NGL (2003 – 358 mcf/d of natural gas and 4 bbl/d of NGL respectively).

Siphon has been, and is currently, an area of focus for us. The area has multiple potentially productive zones and underutilized Company-owned processing facilities making it an attractive candidate for development. During 2003, we acquired the mineral rights to 1,600 acres of land at 100% working interest, acquired 63 km (39 miles) of trade 2-D seismic and 3.4 square km (2.15 square miles) of trade 3-D seismic in the area.

We drilled and cased a 100% working interest well to a depth of 1,803 meters (5,915 feet) at 13-15-86-16W6M during December 2003. Zones of interest include formations in the Permian, Triassic and Cretaceous periods. Due to extreme industry demand for services, we were unable to secure the equipment necessary for completion and testing of this well until mid-March 2004. The Belloy interval was perforated, however efforts to fracture stimulate this zone were unsuccessful and the zone was abandoned. Subsequent to spring breakup we completed and tested several formations at various times during the first nine months of 2004. A pipeline was constructed during the fourth quarter of 2004 from this well to our Siphon processing facility and the well was brought on production in early January 2005 at approximately 200 mcf/d.

We have acquired additional land in the area in 2005 and are currently evaluating two additional seismically identified prospects. Depending upon results of those evaluations, we may drill additional wells in the area in 2005.

Mike/Hazel

At December 31, 2004, we held 6,843 gross (5,318 net) acres for an average 78% working interest in undeveloped lands in the Mike/Hazel area of N.E. British Columbia. A portion of these leases will start to expire in the near future. In order to properly evaluate this land prior to expiry, during the winter of 2003/2004 we shot a 70 sq. km (27 sq. mile) 3-D seismic survey over area lands. This seismic program cost approximately $2,200,000 and was acquired at a 100% proprietary interest. We own the survey and may, at our option, offer to sell licensed trade copies to industry partners. Subsequent to geophysical interpretation, we acquired additional mineral rights lands in the area. We also committed to drill a well on certain industry partner lands to earn an interest in three and three quarters sections of mineral rights. We are to pay 100% of the drilling and completion costs to earn 85% of the deep mineral rights on our deep test well. The drilling costs for the A-19-L/94-H-2 well are estimated to be approximately $3.9 million net to us, of which approximately 26% was incurred prior to December 31, 2004. We also drilled the shallower A-81-H/94-H-3 well in February 2005 on our 100% working interest lands at an estimated cost of $1.0 million. Both of these wells were drilled and cased, however as a result of an unusually short winter drilling season due to early warm weather, we were unable to gain the necessary access for well completion and production testing programs. We are currently examining the alternatives to test the two wells as soon as possible.

Buick Creek

We own an average 24% working interest in a producing natural gas property at Buick Creek through our mineral lease of 23,208 gross (5,563 net) acres. We have owned an interest in this field from the date of its original development in the 1950's. This field currently contains 14 natural gas wells mainly producing from the Dunlevy Formation. In 2004, our share of gross sales from this field averaged 998 mcf/d of natural gas and 18 bbl/d of NGL (2003 – 1,094 mcf/d of natural gas, and 20 bbl/d of NGL respectively).

The facility ownership issue at Buick Creek was resolved on June 27, 2003. We became responsible for our share of costs related to facility improvements that occurred in December 2001 by paying approximately $882,000, as well as $107,000 for repairs to the facility in 2002, and $365,000 for facility operating cost adjustments from January 1, 2001 to June 30, 2003.

In March 2004, we participated, as to our 11.25% working interest, in the drilling of a well in the Buick Creek area. The well was cased and completed and put on production at approximately 30 mcf/d (net to us).

In addition, we agreed to participate in two non-company operated in-fill shallow wells at Buick Creek in which we have a 22.5% working interest at a combined capital cost to the Company of $322,000. Both of these wells were drilled and cased during the first quarter of 2005, and are currently awaiting completion and testing operations. If these wells are successful, they would be tied into the Buick Creek plant where we have a 22.5% working interest.

During 2004, we acquired additional lands in the Buick Creek area. Included in the total acreage listed above, we have interests in 10,448 gross (2,861 net) undeveloped acres at Buick Creek.

Wargen

At December 31, 2004, we held 6,895 gross (1,237 net) working interest acres in the Wargen natural gas field for an average 18% working interest, of which 1,400 gross (315 net) acres were undeveloped. Although we have held our interest in certain of these lands since 1952, the initial discovery was made in 1960 with further development between 1968 and 1988. Our sales from this area averaged 294 mcf/d of natural gas and 6 bbl/d of NGL during the year 2004 (2003 – 309 mcf/d and 6 bbl/d of NGL).

During the third quarter of 2002 and the third quarter of 2003, we participated (22.5% working interest) in the acquisition of a wellhead compressor at D-56-C/94-H-6and C-58-C/94-H-6, respectively.

During the fourth quarter of 2002, we acquired certain 3-D seismic coverage over a portion of our lands at Wargen. Upon completion of technical analysis of the seismic and in combination with a competitor's recent dry hole in the immediate vicinity, we determined that the risk of drilling a deep (3,200 meter, 10,500 feet) and expensive exploratory Slave Point test well was too great. Our P&NG rights held on these lands have since expired.

In the fourth quarter of 2001, we farmed out our 50% working interest in 1,397 gross acres of exploratory acreage in the Wargen area to an industry partner. The farmee paid 100% of the capital costs to drill two wells on the lands and we retained a 7.5% gross overriding royalty on the wells' production, which is convertible at payout (at our option) to a 20% working interest. The operator placed one of the wells on production in the first quarter of 2002. Based on internal estimates, we expect that this well will payout in 2005. The second well was completed and tested during the winter of 2002/2003 and remains non-producing.

Clarke Lake

We own a 16% average working interest in 3,370 gross (531 net) acres in the Clarke Lake area. We have owned an interest in these mineral rights since the early 1950's. Field activity over the last 2 years has increased our production in the area. Our sales from this area averaged 230 mcf/d of natural gas during the year 2004 (2003 – 172 mcf/d).

During the third quarter of 2002, we participated (22.5% working interest) in the temporary repair of the A-61-F/94-J-10 well. This well had been suspended since 1978, due to a suspected hole in the casing, but had produced over 47 BCF of natural gas from the Slave Point Formation. During the first quarter of 2003, we participated in the completion of the down-hole repair and testing of this well which resulted in gross restricted natural gas test rates of 1.1 mmcf/d. This well was equipped during mid 2003 and was placed on production during the third quarter of 2003.

In the fall of 2002, we participated in the re-activation of a previously suspended 22.5% working interest natural gas well located at C-54-F/94-J-10 and brought this well on production.

During the second quarter of 2004 we settled a dispute from the year 2000 with the operator of the Buick Creek and Clarke Lake areas. In connection with that settlement we became recognized as 11.5% owner of salt water disposal facilities, and expended $131,000 to acquire an interest in recently installed pipelines in the area.

Other

We have other P&NG leases in northeast British Columbia that are in various stages of evaluation. At December 31, 2004, we held interests in 4,494 gross (752 net) developed acres and 4,121 gross (2,694 net) undeveloped acres in these leases.

As of December 31, 2004, the only remaining convertible carried interest property located in British Columbia was in the Highway area. We hold a 50% net profits interest in the property which is convertible into a 50% working interest. The Highway prospect is currently non-producing with approximately $4 million of capital costs that must be recovered before any payout to us. At present, the Highway prospect is not expected to be placed on production, nor is payout expected to occur in the foreseeable future.

Alberta - Properties

We currently hold a working interest in 6,091 developed (2,567 net) acres and 7,560 gross (5,992 net) undeveloped acres in Alberta.

40 Mile Coulee

In 2003, we acquired the mineral rights to 6,880 contiguous acres of 100% working interest land in southern Alberta, well known for shallow natural gas production. We acquired these lands as a low risk entry into southern Alberta.

During the fourth quarter of 2003, we drilled and cased the first 3 shallow natural gas wells in this project area. The wells were fracture stimulated, tested and are currently awaiting construction of the pipeline and facilities infrastructure. Of the three wells drilled, two were drilled to the Second White Specks Formation ("SWS") (650 meters or 2,133 feet), while the third well was drilled to test a deeper zone (950 meters or 3,117 feet). Although initial results from the deeper test were promising, extended testing determined that the aerial extent of the pool was limited. Subsequent to abandonment of the deeper zone, we moved up hole and completed and tested the SWS. Test results on the SWS zone for the three wells were 81, 79, and 46 mcf/d respectively.

Based upon the relatively low productivity test results of the three wells, additional drilling success in the project area will be required prior to justifying the capital commitment to build pipelines and facilities.

During the fourth quarter of 2003, we shot 31.2 km (19.5 miles) of 100% interest proprietary 2-D seismic over our lands. This seismic was shot to identify possible deeper and economically more attractive horizons than the SWS. During the summer of 2004 we focused on preparing for the northeast British Columbia winter drilling season. As a result, we suspended further activity in the area. Evaluation and interpretation of the proprietary 2-D seismic shot in late 2003 did not support further drilling initiatives in the area. While natural gas is certainly present, current gas prices and the capital cost of facilities and pipelines to produce these wells do not provide a sufficient return on investment at the present time. Should gas prices increase further, pipeline infrastructure move closer to our lands in the area, new geological data become available, or economics improve, we may revisit this decision.

We are considering becoming more active in the Province of Alberta.

Arctic Islands – Properties

As of December 31, 2004, we held working interests in 45,100 gross acres and carried interests in 133,260 gross acres in the Sverdrup Basin, located in the Arctic Islands. An estimated summary of our ownership interests in Arctic Island lands is as follows:

	Acreage		**Canada Southern Ownership**	
	Gross	Net(1)	Working Interest	Carried Interest
Bent Horn	4,590	230	-	5.00%
Drake Point	9,112	568	6.23%	-
Drake Point	757	227	-	30.00%
Hecla	114,135	34,241	-	30.00%
Kristoffer Bay	2,638	132	-	5.00%
Roche	1,495	45	3.00%	--
Romulus	6,095	914	-	15.00%
Whitefish	2,163	137	6.30%	-
Whitefish	32,330	1,066	3.30%	-
Whitefish	5,045	1,514	-	30.00%
Total	178,360	39,074		

(1) For purposes of the preceding table, net carried interest acres were determined on an "after conversion to working interest" basis as until payout is reached we are not entitled to any cash flows from the property.

To promote drilling in Canada's north, during the 1980's, the Canadian Federal Government provided incentives to oil and gas companies to explore for hydrocarbons. One such incentive enabled companies to hold acreage by deeming to have achieved "Significant Discovery" status. If exploratory wells were drilled and resulted in the discovery of oil or gas, the interest in these lands would be continued for an extended period of time pending future development. The Canadian Federal Government has designated the Bent Horn, Drake Point, Hecla, Kristoffer Bay, Roche Point, Romulus and Whitefish fields as Significant Discovery Lands.

Panarctic Oils Ltd., the operator, received Federal government regulatory approvals for a pilot project to move shipments of crude oil from the Bent Horn field by tanker through the Northwest Passage to southern Canada in 1985. Through December 31, 1996, approximately 2.7 million barrels of Bent Horn crude had been sold. In 1996, the operator shut down production from the field and dismantled the production facilities because of economic uncertainties. We own a 5% carried interest in Bent Horn, which has not yet reached payout status. The timing of payout is uncertain.

We expect that minimal exploration, development and production activity will occur in the Arctic region over the foreseeable future.

Currently, we have no proved or probable reserves attributable to our interests in these Arctic properties.

We have over 4,800 kilometres (1,853 miles) of 2-D seismic data covering certain areas of the Arctic.

Northwest Territories - Properties

We own a 45% carried interest in 1,613 gross acres in the Celibeta field located in the Northwest Territories. This field (ex-permit 2713) was designated as a Significant Discovery Land by the Federal Government. There is no current activity on this land and it has not paid out. Future development of this shut-in gas field is at the discretion of the operator.

Currently, we have no proved or probable reserves attributable to our interests in these Northwest Territories properties.

Saskatchewan - Properties

We currently hold a 79.4% working interest in a shut-in natural gas well and 1,280 gross acres in the Little Pine area of Saskatchewan. Industry competitors have become more active in the area. Depending on gas pricing and other economic considerations, it may become economic for us to place our presently shut-in gas well on production.

Employees

As of December 31, 2004, we employed 6 people.

STATEMENT OF RESERVE DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "Statement") is dated March 17, 2005 and the effective date of the Statement is December 31, 2004. The preparation date of the GLJ Report is March 17, 2005. As of the preparation date, GLJ was not aware of any new information (other than commodity pricing assumptions which may differ from those used in their analysis) which could materially impact their evaluation.

Disclosure of Reserves Data

As a Canadian issuer, we are required under Canadian law to comply with National Instrument 51-101 *"Standards of Disclosure for Oil and Gas Activities"* (NI 51-101) issued by the Canadian Securities Administrators, in all of our reserves related disclosures. Canadian NI 51-101 was effective September 30, 2003 and applies to financial years ended on or after December 31, 2003. Canadian NI 51-101 mandates significant changes in the way reporting issuers are required to determine and publicly disclose information relating to oil and gas reserves.

The purpose of Canadian NI 51-101 is to enhance the quality, consistency, timeliness and comparability of crude oil and natural gas activities by reporting issuers and elevate reserves reporting to a higher level of confidence and accountability.

In the United States however, registrants, including foreign private issuers like us, are generally required to disclose proved reserves using the standards contained in the United States Securities and Exchange Commission ("SEC") Regulation S-X. Under certain circumstances, applicable U.S. law permits us to comply with our own country's law if the requirements vary. The primary difference between the two standards is the additional requirement under NI 51-101 to disclose both proved and proved plus probable reserves as well as related future net revenues using forecast prices and costs. Another difference lies in the definition of proved reserves. As discussed in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook"), the standards which NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the two standards is not material.

Prior to becoming a foreign private issuer in 2004, we were disclosing our reserves using the SEC standards. Since the transition to a foreign private issuer, and considering that the difference in proved reserves (based on constant pricing and costs) between the two standards is not material, we believe that providing our reserves under NI 51-101 provides disclosure which is more consistent with our Canadian peer companies.

The reserves data set forth below (the "Reserves Data") is based upon an evaluation by GLJ with an effective date of December 31, 2004. The Reserves Data summarized the oil, liquids and natural gas reserves of Canada Southern and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs, before and after taxes. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. Canada Southern engaged GLJ to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of our reserves at December 31, 2004 were located in Canada and, specifically, in the provinces of British Columbia, Alberta and Saskatchewan, and the Yukon.

Reserves Data (Constant Prices and Costs)
at December 31, 2004

	Light and Medium Oil			Natural Gas			Natural Gas Liquids		
	Company Interest (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Company Interest (Mmcf)	Gross (Mmcf)	Net (Mmcf)	Company Interest (Mbbls)	Gross (Mbbls)	Net (Mbbls)
Proved									
Developed Producing	1.0	0.8	0.9	6,886	5,837	5,723	55	50	43
Developed Non-Producing	-	-	-	278	271	210	3	3	3
Undeveloped	-	-	-	-	-	-	-	-	-
Total Proved	1.0	0.8	0.9	7,164	6,108	5,933	58	54	46
Probable	0.3	0.3	0.3	2,375	2,102	1,808	11	10	9
Total Proved Plus Probable	1.3	1.1	1.2	9,539	8,210	7,740	69	63	55

Net Present Value of Future Net Revenue (Constant Prices and Costs)
at December 31, 2004

	Before Tax Present Worth Discounted at					
($000s)	0%	5%	10%	12%	15%	20%
Proved						
Developed Producing	26,251	22,262	19,680	18,867	17,810	16,366
Developed Non-Producing	1,194	1,011	870	823	760	672
Undeveloped	-	-	-	-	-	-
Total Proved	27,445	23,273	20,550	19,690	18,570	17,038
Probable	8,972	6,679	5,371	4,981	4,490	3,846
Total Proved Plus Probable	36,417	29,952	25,920	24,671	23,059	20,884

	After Tax Present Worth Discounted at					
($000s)	0%	5%	10%	12%	15%	20%
Proved						
Developed Producing	19,679	16,602	14,611	13,985	13,172	12,065
Developed Non-Producing	765	640	547	516	474	416
Undeveloped	-	-	-	-	-	-
Total Proved	20,444	17,242	15,158	14,501	13,646	12,481
Probable	5,852	4,321	3,455	3,198	2,876	2,455
Total Proved Plus Probable	26,296	21,563	18,613	17,699	16,522	14,936

Notes
In the tables set forth above and elsewhere in this AIF the following definitions and other notes are applicable:

(1) "Gross" means:

(a) In relation to Canada Southern's interest in production and reserves, "Canada Southern's gross reserves", which are Canada Southern's interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of Canada Southern;

(b) In relation to wells, the total number of wells in which Canada Southern has an interest; and

(c) In relation to properties, the total area of properties in which Canada Southern has an interest.

(2) "Net" means:

(a) In relation to Canada Southern's interest in production and reserves, "Canada Southern's net reserves", which are Canada Southern's interest (operating and non-operating) share after deduction of royalties obligations, plus Canada Southern's royalty interest in production or reserves.

(b) In relation to wells, the number of wells obtained by aggregating Canada Southern's working interest in each of its gross wells; and

(c) In relation to Canada Southern's interest in a property, the total area in which Canada Southern has an interest by the working interest owned by Canada Southern.

(3) Reserve Categories - Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

(a) Analysis of drilling, geological, geophysical and engineering data;

(b) The use of established technology; and

(c) Specified economic conditions (see the discussion of "Economic Assumptions" below).

Reserves are classified according to the degree of certainty associated with the estimates. Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

(4) "Economic Assumptions" will be the prices and costs used in the estimate, namely:

(a) Constant prices and costs as at the last day of Canada Southern's financial year; and

(b) Forecast prices and costs

(5) Development and Production Status - Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(b) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or if shut-in, they must have previously been on production and the date of resumption of production must be known with reasonable certainly.

(c) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(d) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved or probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

(6) Levels of Certainty for Reported Reserves - The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) At least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;

(b) At least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

(7) Forecast prices and costs - Future prices and costs that are:

(a) Generally acceptable as being a reasonable outlook of the future; and

(b) If, and only to the extent that, there are fixed or presently determinable future prices or costs to which Canada Southern is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast summary table under "Pricing Assumptions" identifies benchmark reference pricing that apply to Canada Southern.

(8) Constant prices and costs - Prices and costs used in an estimate that are:

(a) Canada Southern's prices and costs as at the effective date of the estimation, held constant throughout the estimated lives of the properties to which the estimate applies; and

(b) If, and only to the extent that, there are fixed or presently determinable future prices or costs to which Canada Southern is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

For the purposes of paragraph (a), Canada Southern prices are the posted prices for oil and the spot price for gas, after historical adjustments for transportation, gravity and other factors.

(9) The Alberta royalty tax credit ("ARTC") is included in the cumulative cash flow amounts. ARTC is based on the program announced in November 1989 by the Alberta government with modifications effective January 1, 1995. Canada Southern qualifies for the maximum ARTC.

(10) Future income tax expense - Future income tax expenses estimate:

(a) Making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes;

(b) Without deducting estimated future costs that are not deductible in computing taxable income;

(c) Taking into account estimated tax credits and allowances; and

(d) Applying to the future pre-tax net cash flows relating to Canada Southern's oil and gas activities the appropriate year-end statutory rates, taking into account future tax rates already legislated.

(11) "Development well" means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon know to be productive.

(12) "Development costs" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building, and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;

(b) Drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) Acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) Provide improved recovery systems.

(13) "Exploration well" means a well that is not a development well, a service well or a stratigraphic test well.

(14) "Exploration costs" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities are:

(a) Costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) Costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) Dry hole contributions and bottom hole contributions;

(d) Costs of drilling and equipping exploratory wells; and

(e) Costs of drilling exploratory type stratigraphic test wells.

(15) "Service well" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

(16) Numbers may not add due to rounding.

(17) The estimates of future net revenue presented in the tables do not represent fair market value.

(18) Disclosure provided herein in respect of boe should be used with caution, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbls is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(19) Estimated further abandonment and reclamation costs related to a property have been taken into account by GLJ in determining reserves that should be attributable to a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated further well abandonment costs.

(20) Both the constant and forecast price and cost assumptions assume the continuance of current laws and regulations.

(21) The extended character of all factual data supplied to GLJ were accepted by GLJ as represented. No field inspection was conducted.

Total Future Net Revenue Undiscounted (Constant Prices and Costs)
at December 31, 2004

($000s)	Revenue	Royalties	Operating Costs	Capital Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Proved								
Developed Producing	42,304	7,085	8,528	440	-	26,251	6,572	19,679
Developed Non-Producing	1,963	441	245	83	-	1,194	429	765
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	44,266	7,526	8,774	522	-	27,445	7,002	20,444
Probable	14,746	3,115	2,357	302	-	8,972	3,119	5,852
Total Proved Plus Probable	59,012	10,641	11,131	824	-	36,417	10,121	26,296

Net Present Value of Future Net Revenue by Production Group (Constant Prices and Costs)
at December 31, 2004

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($000s)
Proved Reserves	Light and medium crude oil (including solution gas and other by-products)	36
	Natural gas (including by-products but excluding solution gas and by-products from oil wells)	20,500
		20,536
Proved Plus Probable Reserves	Light and medium crude oil (including solution gas and other by-products)	42
	Natural gas (including by-products but excluding solution gas and by-products from oil wells)	25,886
		25,928

Reserves Data (Forecast Prices and Costs)
at December 31, 2004

	Light and Medium Oil			Natural Gas			Natural Gas Liquids		
	Company Interest (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Company Interest (Mmcf)	Gross (Mmcf)	Net (Mmcf)	Company Interest (Mbbl)	Gross (Mbbl)	Net (Mbbl)
Proved									
Developed Producing	1.0	0.8	0.9	6,803	5,754	5,658	54	50	42
Developed Non-Producing	-	-	-	278	271	210	3	3	3
Undeveloped	-	-	-	-	-	-	-	-	-
Total Proved	1.0	0.8	0.9	7,080	6,025	5,867	57	53	45
Probable	0.3	0.3	0.3	2,349	2,073	1,787	11	9	9
Total Proved Plus Probable	1.3	1.1	1.2	9,429	8,097	7,655	68	62	54

Net Present Value of Future Net Revenue (Forecast Prices and Costs)
at December 31, 2004

	Before Tax Present Worth Discounted at					
($000s)	0%	5%	10%	12%	15%	20%
Proved						
Developed Producing	24,244	20,472	18,131	17,404	16,460	15,175
Developed Non-Producing	1,023	871	754	715	662	588
Undeveloped	-	-	-	-	-	-
Total Proved	25,267	21,343	18,885	18,118	17,122	15,763
Probable	8,111	5,827	4,652	4,314	3,892	3,346
Total Proved Plus Probable	33,378	27,170	23,537	22,432	21,015	19,109

	After Tax Present Worth Discounted at					
($000s)	0%	5%	10%	12%	15%	20%
Proved						
Developed Producing	18,376	15,439	13,606	13,036	12,297	11,293
Developed Non-Producing	654	551	472	446	411	363
Undeveloped	-	-	-	-	-	-
Total Proved	19,030	15,990	14,078	13,482	12,708	11,656
Probable	5,290	3,763	2,984	2,762	2,485	2,127
Total Proved Plus Probable	24,320	19,753	17,062	16,244	15,193	13,783

Total Future Net Revenue Undiscounted (Forecast Prices and Costs)
at December 31, 2004

($000s)	Revenue	Royalties	Operating Costs	Capital Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Proved								
Developed Producing	40,341	6,801	8,855	440	-	24,244	5,868	18,376
Developed Non-Producing	1,765	394	265	83	-	1,023	369	654
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	42,106	7,196	9,120	523	-	25,267	6,237	19,030
Probable	13,806	2,806	2,581	308	-	8,111	2,821	5,290
Total Proved Plus Probable	55,912	10,002	11,701	831	-	33,378	9,058	24,320

Net Present Value of Future Net Revenue by Production Group (Forecast Prices and Costs)
at December 31, 2004

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($000s)
Proved Reserves	Light and medium crude oil (including solution gas and other by-products)	33
	Natural gas (including by-products but excluding solution gas and by-products from oil wells)	18,839
		18,872
Proved Plus Probable Reserves	Light and medium crude oil (including solution gas and other by-products)	39
	Natural gas (including by-products but excluding solution gas and by-products from oil wells)	23,508
		23,547

Summary of Pricing Assumptions (Constant Prices and Costs)

The following table sets out the benchmark reference prices, as at December 31, 2004, reflected in the Reserves Data. These price assumptions were provided to us by GLJ, our independent qualified evaluator.

Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40^{O} API ($Cdn/bbl)	AECO Gas Price ($Cdn/ mmbtu)	B.C. CanWest Plant Gate ($Cdn/ mmbtu)	B.C. Spot Plant Gate ($Cdn/ mmbtu)	Edmonton Propane ($Cdn/bbl)	Edmonton Butane ($Cdn/bbl)	Edmonton Pentanes Plus ($Cdn/bbl)	Inflation Rate (%/year)	Exchange Rate ($US/$Cdn)
Historical										
2001	25.97	39.40	6.21	6.76	6.29	31.85	31.17	42.48	2.6	0.6448
2002	26.08	40.33	4.04	3.64	3.93	21.39	27.08	40.73	2.2	0.6376
2003	31.07	43.66	6.66	5.71	6.32	32.14	34.36	44.23	2.8	0.7213
2004	41.38	52.96	6.88	5.54	6.44	34.70	39.97	54.07	1.9	0.7734
As at December 31,2004	43.45	46.54	6.79	5.44	6.49	29.79	34.44	48.97		0.8308

Pricing and Inflation Rate Assumptions (Forecast Prices and Costs)

The following table sets out the benchmark reference prices, as at December 31, 2004, reflected in the Reserves Data. These price assumptions were provided to us by GLJ, our independent qualified evaluator.

Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40^{O} API ($Cdn/bbl)	AECO Gas Price ($Cdn/ mmbtu)	B.C. CanWest Plant Gate ($Cdn/ mmbtu)	B.C. Spot Plant Gate ($Cdn/ mmbtu)	Edmonton Propane ($Cdn/bbl)	Edmonton Butane ($Cdn/bbl)	Edmonton Pentanes Plus ($Cdn/bbl)	Inflation Rate (%/year)	Exchange Rate ($US/$Cdn)
Forecast										
2005	42.00	50.25	6.60	5.25	6.30	32.25	37.25	50.75	2.0	0.82
2006	40.00	47.75	6.35	5.90	6.10	30.50	35.25	48.25	2.0	0.82
2007	38.00	45.50	6.15	5.90	5.90	29.00	33.75	46.00	2.0	0.82
2008	36.00	43.25	6.00	5.75	5.75	27.75	32.00	43.75	2.0	0.82
2009	34.00	40.75	6.00	5.75	5.75	26.00	30.25	41.25	2.0	0.82
2010-2015[1]	33.50	40.08	6.10	5.85	5.85	25.63	29.67	40.58	2.0	0.82
Remainder	Escalate at 2.0% per year								2.0	0.82

(1) Prices represent the average for the period noted.

Canada Southern's weighted average prices received in 2004 were $5.72/mcf for natural gas, $49.15/bbl for oil and $38.48/bbl for NGL.

Reconciliation of Changes in Reserves (Forecast Prices and Costs)

	Light and Medium Oil			Conventional Natural Gas			Natural Gas Liquids		
Factors	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (Mmcf)	Net Probable (Mmcf)	Net Proved Plus Probable (Mmcf)	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)
December 31, 2003	1.1	0.2	1.3	7,511	1,841	9,352	55.0	9.7	64.7
Extensions	-	-	-	31	4	35	0.5	0.1	0.6
Improved recovery	-	-	-	229	48	277	1.3	0.2	1.5
Technical revisions	0.6	0.1	0.7	306	(105)	201	(4.1)	(1.0)	(5.1)
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-	-	-	-
Production	(0.8)	-	(0.8)	(2,210)	-	(2,210)	(7.7)	-	(7.7)
December 31, 2004	0.9	0.3	1.2	5,867	1,788	7,655	45.0	9.0	54.0

Note: The Company has no heavy oil or unconventional reserves (bitumen, synthetic crude oil, natural gas from coal, etc.)

Reconciliation of Changes in Net Present Values of Future Net Revenue Attributable to Net Proved Reserves Discounted at 10% per year (Constant Prices and Costs)

Period and Factor	After Tax 2004 ($000s)	Before Tax 2004 ($000s)
Estimated net present value at beginning of year	15,120	23,185
Oil and gas sales during the period net of production costs and royalties[(1)]	(11,045)	(11,045)
Changes due to prices, production costs and royalties related to forecast production[(2)]	3,384	3,384
Development costs incurred during the period[(3)]	11,506	11,506
Changes in forecast development costs[(4)]	(11,852)	(11,852)
Changes resulting from extensions and improved recovery[(5)]	843	843
Changes resulting from discoveries[(5)]	-	-
Changes resulting from acquisitions of reserves[(5)]	-	-
Changes resulting from dispositions of reserves[(5)]	-	-
Accretion of discount[(6)]	2,319	2,319
Net change in income taxes[(7)]	1,891	-
Changes resulting from technical revisions	1,357	1,357
All other changes	1,636	854
Estimated net present value at end of year	15,158	20,550

(1) Company actual before income taxes, excluding G&A.
(2) The impact of changes in prices and other economic factors on future net revenue.
(3) Actual capital expenditures relating to the exploration, development and production of oil and gas reserves.
(4) The change in forecast development costs for the properties evaluated at the beginning of the period.
(5) End of period net present value of the related reserves.
(6) Estimated as 10% of the beginning of period net present value.
(7) The difference between forecast income taxes at beginning of period and the actual taxes for the period plus forecast income taxes at the end of the period.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook. The significant majority of the undeveloped reserves are scheduled to be developed within the next two years of the effective date.

Significant Factors or Uncertainties

The evaluated oil and gas properties of the Company have no material extraordinary risks or uncertainties beyond those which are inherent of an oil and gas producing company.

Future Development Costs

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserves categories noted below.

($000s)	Forecast Prices and Costs		Constant Prices and Costs	
Year	Proved Reserves	Proved plus Probable Reserves	Proved Reserves	Proved plus Probable Reserves
2005	485	485	485	485
2006	38	346	38	339
2007	-	-	-	-
2008	-	-	-	-
2009	-	-	-	-
Thereafter	-	-	-	-
Total Undiscounted	523	831	523	824
Total Discounted at 10%	495	762	495	756

We expect to fund the future development from operating cash flow and working capital.

Other Oil and Gas Information

Oil and Natural Gas Wells

Productive wells on working and carried interest properties as of December 31, 2004, were as follows**:**

	Gross Wells		Net Wells	
	Gas	Oil	Gas	Oil
Working Interest	64	8	20.5	1.3
Carried Interest	4	-	1.5	-
Total	68	8	22.0	1.3

We also hold overriding royalty interests in 15 wells.

Properties with no Attributable Reserves

Total estimated undeveloped mineral interests held by us as of December 31, 2004 is summarized by geographic area in the table below:

	Working Interest		Carried Interest		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres[(1)]	Gross Acres	Net Acres
Yukon	27,078	8,304	-	-	27,078	8,304
British Columbia	27,423	15,031	-	-	27,423	15,031
Arctic Islands	43,820	1,777	130,700	37,065	174,520	38,842
Alberta	7,560	5,992	-	-	7,560	5,992
Saskatchewan	1,120	952	-	-	1,120	952
Northwest Territories	-	-	806	363	806	363
Total	107,001	32,056	131,506	37,428	238,507	69,484

(1) For purposes of the preceding table, net carried interest acres are determined on an "after conversion to working interest" basis, as until payout is reached we are not entitled to any cash flows from the property.

Abandonment and Reclamation Costs

We have estimated abandonment and salvage value for all producing wells, non-producing wells and facilities. All non-producing well abandonments are scheduled to occur in 2005. Producing well abandonments were scheduled to occur two years after the forecast final production. Abandonment costs for all of our 76 gross (23.3 net) wells were estimated to be between $50,000 and $100,000 per well (net of salvage), except for the Kotaneelee wells which were estimated to be between $1,050,000 and $2,000,000 per well (net of salvage). No abandonment costs were included in the estimation of future net revenues by GLJ.

Year	Total Abandonment and Reclamation Costs Including Well Abandonment and Disconnect Costs Net of Salvage Value ($000s)
2005	261
2006	23
2007	-
2008	45
2009	2,402
Remainder	1,209
Total	3,940
Discounted at 10%	2,216

Capital Expenditures/Incurred

The following table summarizes the capital expenditures related to our activities for the last three years.

	Years ended December 31,		
($000s)	2004	2003	2002
Land and acquisitions	896	850	67
Geological and geophysical	1,151	1,789	100
Drilling and completion	8,749	1,850	148
Facilities and equipment	679	417	151
Other	31	74	8
Total capital expenditures	11,506	4,980	474
Dispositions	-	-	-
Net capital expenditures	11,506	4,980	474

Drilling History

	Gross		Net	
Year	Productive	Dry	Productive	Dry
2004	1	1	0.11	0.11
2003	4	-	4.00	-
2002	-	-	-	-

At December 31, 2004, we had two gross (1.31 net) wells that were in the process of being drilled.

Production Estimates

The following table sets out the gross volume of our production estimated for the year ending December 31, 2005 which is reflected in the estimate of future net revenue disclosed in the tables contained under "Disclosure of Reserves Data" using constant prices and costs. The production forecast is the same on the forecast price case.

Volumes	Light and Medium Oil (bbl/d)	Natural Gas (mcf/d)	Natural Gas Liquids (bbl/d)	BOE (boe/d)
Proved Producing	-	4,832	26	832
Total Proved	-	4,872	27	839
Proved Plus Probable	-	5,016	27	863

For proved producing, total proved and proved plus probable reserves, production in 2005 for the Kotaneelee field accounts for more than 20% of our estimated total daily production. The estimated production for the Kotaneelee field for the year ended December 31, 2005 is identified in the following table.

Volumes (Kotaneelee)	Light and Medium Oil (bbl/d)	Natural Gas (mcf/d)	Natural Gas Liquids (bbl/d)	BOE (boe/d)
Proved Producing	-	3,097	-	516
Total Proved	-	3,097	-	516
Proved Plus Probable	-	3,209	-	535

Production history

The following table indicates our average daily production by area for the last three fiscal years.

	Years ended December 31,		
Boe/d	2004	2003	2002
Kotaneelee	779	1,017	1,432
Buick Creek	185	203	161
Town	77	15	11
Siphon	64	64	81
Wargen	55	57	61
Clarke Lake	38	29	16
Ekwan	5	1	9
Other	3	2	3
Total	1,206	1,388	1,774

SELECTED CONSOLIDATED FINANCIAL INFORMATION

The following table summarizes our selected consolidated information for the last three fiscal years.

		Years ended December 31,	
	2004	2003	2002
		restated	*restated*
Financial			
($000s, except share amounts)			
Gross revenues	13,828	13,183	9,937
Cash flow from operations[1]	8,060	22,228	6,580
Per share – basic	0.56	1.54	0.46
Per share – diluted	0.56	1.54	0.46
Net income (loss)	3,279	17,050	1,849
Per share – basic	0.23	1.18	0.13
Per share – diluted	0.23	1.18	0.13
Capital expenditures, net	11,506	4,980	474
Working capital	34,765	38,212	20,963
Total assets	59,789	62,042	29,121
Shareholders' equity	47,090	42,974	25,671
Shares outstanding	14,417,770	14,417,770	14,417,770
Weighted average shares outstanding			
Basic	14,417,770	14,417,770	14,417,770
Diluted	14,435,234	14,423,667	14,417,770

(1) Cash flow from operations is a non-GAAP measure that does not have a standardized meaning as prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other oil and gas companies. We consider it an important measure as it demonstrates our ability to generate the cash flow necessary to fund future growth through capital investment.

The following summarizes our selected consolidated financial information for the eight most recently completed quarters ending at the end of the most recently completed financial year.

Summary of Quarterly Information

($000s, except per share amounts)

				2004 Quarter ended
	December 31	September 30	June 30	March 31
Total revenues	3,405	3,311	3,642	3,470
Net income (loss)	1,108	445	570	1,156
Per basic share	0.08	0.03	0.04	0.08
Per diluted share	0.08	0.03	0.04	0.08
Capital expenditures, net	6,413	3,038	770	1,285

				2003 Quarter ended
	December 31	September 30	June 30	March 31
	restated	*restated*	*restated*	*restated*
Total revenues	2,571	2,364	4,106	4,142
Settlement of litigation	(1,000)	23,727	-	-
Net income (loss)	(490)	14,857	1,370	1,313
Per basic share	(0.04)	1.03	0.10	0.09
Per diluted share	(0.04)	1.03	0.10	0.09
Capital expenditures, net	3,699	189	553	539

INFORMATION CONCERNING THE OIL AND NATURAL GAS INDUSTRY

Commodity Price Volatility

Oil and natural gas prices are volatile and subject to a number of external factors. Prices are cyclical and fluctuate as a result of shifts in the balance between supply and demand for oil and natural gas, world and North American market forces, conflicts in middle eastern countries, inventory and storage levels, OPEC policy, weather patterns and other factors. OPEC supply curtailment, tensions in the middle east, increased demand in China and low North American crude stocks have kept crude oil prices high. Natural gas prices are greatly influenced by market forces in North America since the primary source of supply is contained within the continent. Market forces include the industry's ability to find new production and reserves to offset and grow declining production, economic factors influencing industrial demand, weather patterns affecting heating demand and the price of oil for fuel switching.

Foreign Currency Exchange Rates

World oil prices are quoted in U.S. dollars and the price received by Canadian producers is therefore affected by the $US/$CDN exchange rate that may fluctuate over time. A material increase in the value of the Canadian dollar relative to its U.S. counterpart had an offsetting effect on the gains in the U.S. denominated WTI oil price.

Seasonality

The exploration for and development of oil and natural gas reserves depends on access to areas where operations are to be conducted. Seasonal weather variations, including freeze-up and break-up affect access in certain circumstances. Natural gas is used principally as a heating fuel and for power generation. Accordingly, seasonal variations in weather patterns affect the demand for natural gas. Depending on prevailing conditions, the prices received for sales of natural gas are generally higher in winter than summer months, while prices are generally higher in summer than spring and fall months.

Industry Consolidation and Competition

Over the past few years, consolidation within the Canadian oil and gas industry has resulted in a significant change in the number of junior to intermediate-sized exploration and production companies. Oil and gas trusts have been in high demand and they are driving the market for corporate and asset acquisitions in Canada. The strength of commodity prices has resulted in significantly increased operating cash flows and has led to increased drilling activity. This industry activity will increase competition for undeveloped lands; skilled personnel; access to drilling rigs, service rigs and other equipment; and access to processing and gathering facilities, all of which may cause drilling and operating costs to increase.

Government Regulation

The oil and natural gas industry is subject to extensive controls and regulation imposed by various levels of government. In western Canada, the various provincial governments have legislation and regulations, which govern land tenure, royalties, production rates, environmental protection, the prevention of waste and other matters. It is not expected that these controls and regulation will affect our operations in a manner materially different than they would affect other oil and gas companies of similar size. We are unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing – Oil and Natural Gas

In Canada, producers of oil and natural gas negotiate sales contracts directly with purchasers, with the result that the market determines the price of oil and natural gas. Exports from Canada may be made pursuant to export contracts with terms not exceeding one year, in the case of light crude, and not exceeding two years, in the case of heavy crude and natural gas, provided that an order approving any such export has been obtained from the National Energy Board ("NEB"). Exports of longer terms require an exporter to obtain an export license from the NEB and the issue of such a license requires the approval of the Governor in Council. In western Canada, the various provincial governments also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere, based on such factors as reserve availability, transportation arrangements and market considerations.

The North American Free Trade Agreement

On January 1, 1994, the North American Free Trade Agreement ("NAFTA") among the governments of Canada, the U.S. and Mexico became effective. The NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the U.S. or Mexico will be allowed, provided that any export restrictions do not (i) reduce the proportion of energy resource exported relative to domestic use (based on the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price; or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements and, except as permitted in enforcement of countervailing and antidumping orders and undertakings, minimum or maximum import price requirements.

The NAFTA contemplates the reduction of restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

Land Tenure

Oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments who grant rights to explore for and produce oil and natural gas pursuant to leases, licenses and permits based upon conditions set forth in provincial legislation. Oil and natural gas rights may also be privately owned and rights to explore for and produce such oil and natural gas are generally granted by lease from the freehold owner on such terms and conditions as may be negotiated.

Provincial Royalties and Incentives

The royalty regime is a significant factor in the profitability of crude oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the freehold mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on the type of product being produced, well productivity, geographical location and field discovery date. From time to time, the various provincial governments in western Canada have established incentive programs, which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration and development. The trend in recent years has been for provincial governments to eliminate these types of programs in favour of long-term programs that enhance predictability for producers.

Crude oil and natural gas royalty holidays for specific wells and royalty rate reductions lower the amount of Crown royalties paid by the Company to the provincial governments. In Alberta, the Alberta royalty tax credit program also provides a rebate, to certain eligible producers, on Alberta Crown royalties paid in respect of eligible producing properties. These incentives result in increased profitability from our operations. In Alberta, the amount payable as a royalty in respect of oil depends upon its vintage and whether it is light, medium or heavy. The royalty payable on natural gas, subject to various incentives, is also dependent upon vintage as well as a prescribed or corporate average price.

In Saskatchewan, the fiscal regime for the oil and gas industry was revised effective October 1, 2002. Some royalties on wells existing as of that date remains unchanged and are subject to various periods of royalty/tax deduction. The changes include new lower royalty and tax structures applicable to oil, natural gas and associated natural gas, a new system of volume incentives and a reduced Corporation Capital Tax Surcharge rate on gross Saskatchewan resource sales.

In British Columbia, the amount payable as a royalty in respect of oil depends on the vintage of the oil, the quantity of oil produced in a month and the value of the oil. The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the amount obtained by the producer and the prescribed minimum price.

In the Yukon, the amount payable on natural gas is a flat rate based on the price we receive for our gas.

Environmental Regulation

Our operations are subject to a variety of federal, provincial and local laws and regulations, some of which relate to the remediation of existing environmental conditions while others require that certain work be carried out at the time of plant closure, or when the specific asset is retired. The most restrictive of these requirements are typically issued to us in the form of permits, approvals, authorizations and licenses that are intended to protect employees from injury and illness and the environment and community from harm. The laws and regulations may limit or regulate operating conditions, rates and efficiency; land, water and raw material use and management; product storage, quality and transportation; waste storage and disposal; emissions and other discharges. Asset retirement obligations are often stipulated in our facility operating licenses and permits, although they may also arise from contractual obligations and other legal requirements then in effect. For facilities with these stipulations, asset retirement obligations typically involve the removal of the asset, remediation of any contamination resulting from the use of that asset and reclamation of the land.

We believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. We are committed to meeting our responsibilities to protect the environment wherever we operate and anticipate making increased expenditures of both a capital and expense nature as a result of increasingly stringent laws relating to the protection of the environment.

RISK FACTORS

An investment in our Common Shares is speculative due to the nature of our involvement in the exploration for, and the acquisition, development and production of, oil and natural gas reserves. An investor should consider carefully the risk factors set out below and consider all other information contained herein and in our other public filings before making an investment decision.

Competition

The natural gas and oil industry is highly competitive. We experience competition in all aspects of our business, including acquiring reserves, leases, licenses and concessions, obtaining the equipment and labor needed to conduct operations and market natural gas and oil. Our competitors include multinational energy companies, other independent natural gas and oil companies and individual producers and operators. Because both natural gas and oil are fungible commodities, the principal form of competition with respect to product sales is price competition. Many competitors have financial and other resources substantially greater than those available to us and, accordingly, may be better positioned to acquire and exploit prospects, hire personnel and market production. In addition, many of our competitors may be better able to respond to factors such as changes in worldwide natural gas or oil prices, levels of production, the cost and availability of alternative fuels or the application of government regulations. Such factors, which are beyond our control, may affect demand for our natural gas and oil production. We expect a high level of competition to continue.

Dependence on one major property

During 2004, our core property at Kotaneelee contributed 65% of our total production. Kotaneelee continues to experience a decrease in formation reservoir pressure, an increase in water production, and as a result, a decrease in natural gas production. There is a possibility that our cash flow from Kotaneelee could either be significantly reduced or terminated at any time in the future.

Further development of the Kotaneelee field may assist with the recovery of the existing remaining reserves and identify additional reserves. However, future development of Kotaneelee is highly risky due to the geographic location, geological complexity, depth and temperature of the producing formation, inherent risks of seismic interpretations and the costs of drilling. Challenges encountered during the recent drilling of Kotaneelee L-38 well highlight the major risks associated with the property. Due to the presence of numerous geological faults in the area, our seismic interpretation was challenging (geophysical risk) and resulted in the sidetrack drilling operation when the target formation (Nahanni) was not encountered. Upon encountering the Nahanni Formation with the sidetrack operation, the next challenge to overcome was to attempt to encounter the fracture system (geological risk) that assists in natural gas production from this otherwise tight reservoir. If a fracture system was not encountered, the well would most likely not be commercial. Having successfully encountered a fracture system, the next risk is whether that fracture system is connected to commercial quantities of hydrocarbons. As part of the completion operation, the well was flowed for a short period of time. However, due to the warm weather in the area and the rapidly deteriorating ice bridges, the decision was made to suspend the flow and remove the drilling rig and test equipment to avoid paying standby charges. Otherwise, the equipment would need to remain on location until approximately June when the river is open for barging operations. While there is natural gas present, there is currently insufficient information to estimate expected flow rates or to estimate recoverable proven reserves. Testing will be performed after the well is tied in during the second quarter of 2005. We agreed with the operator's decision to remove the drilling and testing equipment, and to incur the cost and risk of tying in prior to testing. However, readers are cautioned that presently we do not have sufficient information to determine whether or not the well will be commercially successful. As a result, the next group of major risks includes the sustainable production rates, the impact of this well on the other producing wells, if any, and the amount of water production (production risk). As the water disposal facilities have a limited amount of capacity, when water production exceeds that capacity either additional capital would have to be spent to increase capacity or wells production would have to be reduced to decrease water production, which could ultimately lead to having the wells shut-in. The decision as whether to expand water disposal facilities would be based on project economics at the time. As such, the presence and predicted amounts of water are factors used by independent reserve evaluators in determining the amount of additional proved reserves, if any are discovered.

As a result of the geophysical and geological risks associated with the Kotaneelee L-38 well, the original gross estimated costs of the drilling project have almost doubled from $16 million to $30 million (exclusive of completion, equipping and tie-in costs) (cost risk).

Unless we can successfully drill for or acquire economically viable reserves of natural gas and crude oil in other areas, as our reserves at Kotaneelee deplete, our operating results may be materially adversely affected.

Exploration and development risks

Exploration and development of natural gas and oil involves a high degree of risk that no commercial production will be obtained or that the production will be insufficient to recover drilling and completion costs. The costs of drilling, completing, and operating wells are sometimes uncertain, and cost overruns in exploration and development operations can adversely affect the economics of a project. Our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including mineral lease title deficiencies, equipment failures, weather conditions, shortages or delays in sourcing qualified personnel, shortages or delays in the delivery of equipment, ability to access surface topography, compliance with governmental requirements, and fires and explosions. Furthermore, completion of a well does not ensure a profit on the investment or a recovery of the drilling, completion and tie-in costs.

We cannot be certain that the exploratory or development wells we drill will be productive or that we will recover all or any portion of our investments. In order to increase the chances for success, we often invest in seismic or other geoscience data to assist us in identifying potential drilling candidates. Additionally, the cost of drilling, completing and testing wells is often uncertain at the time of our initial investment. Depending on complications encountered while drilling, the final cost of the well may significantly exceed that which we originally estimated.

Commodity price fluctuations

Our products, including natural gas, NGL's and oil, and other hydrocarbon products, are commodities. Because our contracts do not fix a long-term price for the products we purchase or sell, market changes in the price of such products can have a direct and immediate effect (whether favorable or adverse) upon our revenues and profitability. Prices for products may be subject to material change in response to relatively minor changes in supply and demand, general economic conditions and other market conditions over which we have no control. As the majority of our production is from natural gas sales, the price of crude oil does not have a large impact in our profitability. Other conditions affecting our business include the level of domestic oil and gas production, the availability and prices of competing commodities and of alternative energy sources, the availability of local, intraprovincial and interprovincial transportation systems with adequate capacity, the proximity of gas production to gas pipelines and facilities, the availability of pipeline capacity, government regulation, the seasons, the weather and the impact of energy conservation efforts.

Access to additional mineral rights for expansion in the Yukon Territory

The Yukon Government has been attempting to resolve native land claim issues on presently un-leased acreage surrounding our Kotaneelee leases. Until such time as these land claim issues have been resolved, we believe that no additional lands in the area will be leased for future oil and gas exploration and development. With Kotaneelee's remaining recoverable reserves rapidly depleting, it is possible that we may be required to abandon our field and facilities before they could be utilized as strategic assets to provide us with a competitive advantage in acquiring new mineral leases in the surrounding area.

Estimating of reserves and future net cash flows risk

Estimating natural gas, natural gas liquids and crude oil reserves, and future net cash flows include numerous uncertainties, many of which may be beyond our control. Such estimates are essential in our decision-making, as to whether further investment is warranted. These estimates are derived from several factors and assumptions, some of which are:

- reservoir characteristics based on variable geological, geophysical and engineering assessments;
- future rates of production based on historical production draw-down rates;
- future net cash flows based on commodity price/quality assumptions, production costs, taxes and investment decisions;
- recoverable reserves based on estimated future net cash flows; and
- compliance expectations based on assumed federal, provincial and environmental laws and regulations.

Ultimately, actual production rates, reserves recovered, commodity prices, production costs, government regulations or taxation may differ materially from those assumed in earlier reserve estimates. Higher or lower differences could materially impact our production, revenues, production costs, depletion expense, taxes and capital expenditures.

Reserve estimates and net present values reported by us elsewhere in this document are based on independent third party estimated escalated commodity prices and associated production costs that are assumed for the life of the reserves. Actual future prices and costs may be materially higher or lower.

Replacement of reserves

In general, the rate of production from natural gas and oil properties declines as reserves are depleted. The rate of decline depends on reservoir characteristics and other factors. Except to the extent we acquire properties containing proved reserves or conduct successful exploration and development activities, or both, our estimated proved reserves will decline as reserves are produced. Our future natural gas and oil production, and therefore cash flow from operations and net earnings, are highly dependent upon our level of success in finding or acquiring additional economically recoverable reserves. The business of exploring for, developing and acquiring reserves is capital intensive. To the extent cash flow from operations is reduced and external sources of capital become limited or unavailable, our ability to make the necessary capital investment to maintain or expand our asset base of natural gas and oil reserves could be materially impaired.

Risks pertaining to acquisitions and joint ventures

As part of implementing our business strategy, we may consider expanding our business through the acquisition of oil and gas properties or companies. Our ability to expand in this manner would depend upon our ability to identify suitable acquisitions, complete the acquisitions, and effectively integrate any acquired assets or companies into our current business operations. Suitable acquisitions, on terms acceptable to us, may not be available in the future or may require us to assume certain liabilities, including, without limitation, environmental liabilities, known or unknown. Should suitable acquisition candidates be evaluated, we may require debt financing and/or additional equity to be raised to fund the acquisition. As we currently have no debt and have not raised equity during the past few years, it is not certain that we could obtain suitable financing to close an acquisition.

Potential variability in quarterly operating results

The exploration for and development of oil and natural gas reserves depends on access to areas where operations are to be conducted. Seasonal weather variations, including freeze-up and break-up affect access in certain circumstances. Natural gas is used principally as a heating fuel and for power generation. Accordingly, seasonal variations in weather patterns affect the demand for natural gas. Depending on prevailing conditions, the prices received for sales of natural gas are generally higher in winter than summer months, while prices are generally higher in summer than spring and fall months. Accordingly, any increase or decrease in our net operating revenues and their effects on profitability cannot be predicted. Because of the seasonality of our business and continuous fluctuations in the prices of our products, our operating results for any past quarterly period may not necessarily be indicative of results for future periods and there can be no assurance that we will be able to maintain steady levels of profitability on a quarterly or annual basis in the future.

Operating hazards and uninsured risks

The oil and gas business involves a variety of operating risks, including fire, explosion, pipe failure, casing collapse, abnormally high pressured formations, adverse weather conditions, governmental and political actions, native rights, surface topography, limited or no access during summer months, premature reservoir declines, and environmental hazards such as oil spills, gas leaks and discharges of toxic gases. The occurrence of any of these events with respect to any property operated or owned (in whole or in part) by us could have a material adverse impact on us. We, and the operators of our properties, maintain insurance in accordance with customary industry practices and in amounts that we believe to be reasonable. However, insurance coverage is not always economically feasible and is not obtained to cover all types of operational risks. The occurrence of a significant event that is not fully insured could have a material adverse effect on our financial condition.

Drilling plans subject to change

A prospect is a property on which our geoscientists have identified what they believe, based on available seismic and geological information, to have indications of hydrocarbons. Our prospects are in various stages of review. Whether or not we ultimately drill a prospect may depend on the following factors: receipt of additional seismic data or reprocessing of existing data and interpretation; material changes in oil or gas prices; the costs and availability of drilling equipment; success or failure of wells drilled in similar formations, availability of capacity in existing facilities and pipelines; availability and cost of capital; changes in the estimates of costs to drill or complete wells; our ability to attract other industry partners to acquire a portion of the working interest to reduce exposure to costs and drilling risks; decisions of our joint working interest owners; and restrictions imposed by governmental agencies. We will continue to gather data about our prospects, and it is possible that additional information may cause us to alter our drilling schedule or determine that a prospect should not be pursued at all.

Shortage of supplies and equipment

Our ability to conduct operations in a timely and cost effective manner is subject to the availability of natural gas and crude oil field supplies, rigs, equipment and service crews. Although none are expected currently, any shortage of certain types of supplies and equipment could result in delays in our operations as well as in higher operating and capital costs.

Restoration, safety and environmental risk

Certain laws and regulations exist that require companies engaged in petroleum activities to obtain necessary safety and environmental permits to operate. Such legislation may restrict or delay us from conducting operations in certain geographical areas. Further, such laws and regulations may impose liability on us for remedial and clean-up costs, personal injuries related to safety and environmental damages.

While our safety and environmental activities have been prudent and have enabled us to operate successfully in managing such risks, there can be no assurance that we will always be successful in protecting ourselves from the impact of all such risks. Consistent with our growth in other areas, we seek opportunities for performance improvement in our operating practices.

Government regulation and environmental matters

We are subject to various federal and provincial laws and regulations including environmental laws and regulations. We believe that we are in substantial compliance with such laws and regulations, however, such laws and regulations may change in the future in a manner that will increase the burden and cost of compliance. In addition, we could incur significant liability for damages, cleanup costs and penalties in the event of certain discharges into the environment.

Certain laws and governmental regulations may impose liability on us for personal injuries, clean-up costs, environmental damages and property damages, as well as administrative, civil and criminal penalties. We maintain limited insurance coverage for sudden and accidental environmental damages, but do not maintain insurance coverage for the full potential liability that could be caused by sudden and accidental environmental damage. Accordingly, we may be subject to liability or may be required to cease production from properties in the event of such damages.

Kyoto Protocol risk

The Kyoto Protocol treaty (Protocol) was established in 1997 to reduce emissions of greenhouse gases (GHG) that are believed to be responsible for increasing the Earth's surface temperatures and affecting the global climate change. Canada ratified the Protocol in December 2002. Since the implementation of the Protocol, approximately 160 countries have committed to reduce GHG internationally. Canada has committed to meet a 6% reduction of emission over base-year 1990 during the period 2008 to 2012. Canadian government assurances of cost and volume limits suggest that incremental risks and liabilities attributable to addressing Protocol related policies are manageable. It is not possible to predict the impact of how Protocol-related policies will ultimately be resolved and to what extent their impact will affect our future unit operating costs and capital expenditures.

DIVIDENDS

We have never paid dividends. Any decision to pay dividends will be made by the Board of Directors from time-to-time and will be subject to earnings and financial requirements and other conditions prevailing at that time.

DESCRIPTION OF CAPITAL STRUCTURE

General Description of Capital Structure

Details of our capital structure are discussed under the heading "Liquidity and Capital Resources" in our 2004 Management's Discussion & Analysis and are disclosed in note 9 to the consolidated financial statements for the year ended December 31, 2004.

MARKET FOR SECURITIES

Trading Price and Volume

Our Common Shares are listed and traded on the Toronto Stock Exchange (TSX) under the symbol "CSW", the Pacific Stock Exchange and the Boston Stock Exchange under the symbol "CSW" and on the NASDAQ SmallCap Market ("NASDAQ") under the symbol "CSPLF".

The following table sets out the high and low price and trading volume of our Common Shares on the TSX for 2004 on a monthly basis.

Month *(2004)*	**High Price** *($Cdn)*	**Low Price** *($Cdn)*	**Closing Price** *($Cdn)*	**Volume**
January	7.50	6.25	6.50	23,500
February	7.00	6.30	6.57	23,000
March	7.50	6.25	6.30	43,100
April	7.00	5.90	6.20	37,300
May	6.20	5.10	5.53	22,900
June	7.34	5.43	7.00	55,100
July	7.30	6.11	6.80	36,700
August	6.97	5.70	6.06	34,300
September	6.05	5.35	5.65	18,300
October	7.80	5.70	7.80	49,700
November	8.57	7.30	7.31	17,300
December	9.55	6.85	9.00	77,800

The following table sets out the high and low price and trading volume of our Common Shares on NASDAQ for 2004 on a monthly basis.

Month *(2004)*	**High Price** *($U.S.)*	**Low Price** *($U.S.)*	**Closing Price** *($U.S.)*	**Volume**
January	5.48	4.81	5.00	636,200
February	5.19	4.50	4.92	495,700
March	5.70	4.70	4.89	1,092,600
April	5.01	4.35	4.49	639,100
May	4.72	3.17	4.04	541,500
June	5.44	3.65	5.27	489,400
July	5.54	4.55	5.09	427,700
August	5.26	4.07	4.61	500,300
September	4.78	4.08	4.48	253,200
October	6.70	4.42	6.47	1,079,700
November	7.23	6.00	6.20	731,100
December	7.80	5.20	7.50	968,500

Prior Sales

In the most recently completed financial year, we did not issue any shares that are not listed or quoted on a securities exchange or other marketplace.

DIRECTORS AND EXECUTIVE OFFICERS

Name, Occupation and Security Holding

The names, municipalities of residence, positions with the Corporation and principal occupation of the directors and executive officers of the Corporation are set out below and, in the case of the directors, the period each has served as a director of Canada Southern. The term of office of each director expires at our next annual general meeting of shareholders.

Name, Municipality of Residence, and Position with the Corporation	Principal Occupation	Director Since	Common Shares Beneficially Owned[4] at December 31, 2004
Richard C. McGinity[1][2][3] Crowheart, Wyoming Chairman of the Board and Director	President, School Street Capital Group (a merchant banking company)	2002	53,000
Arthur B. O'Donnell[1][2] West Hartford, Connecticut Director	Retired Businessman	1997	51,654
Myron F. Kanik[1][2][3] Calgary, Alberta Director	President, Kanik & Associates Ltd. (an energy industry consulting company) since 1999. President of the Canadian Energy Pipeline Association from 1993 to 1999. Director, AltaGas Income Trust (a midstream trust).	2002	50,000
Raymond P. Cej[1][2][3] Calgary, Alberta Director	President, BA Energy Inc. (an oilsands energy company) since 2003, President and Chief Operating Officer of Synenco Energy Inc. (an oilsands energy company) from 2001 to 2003. Director of GEOCAN Energy Inc. (an energy company) since 2003.	2004	50,000
John W.A. McDonald Calgary, Alberta President and Chief Executive Officer and Director	President and Chief Executive Officer of Canada Southern since April 2004. Vice President of AltaGas Services Inc. (a midstream company) from 1996 to 2004.	2004	12,333
Randy L. Denecky Calgary, Alberta Chief Financial Officer	Chief Financial Officer of Canada Southern since 2001 and Acting President of Canada Southern from 2002 to 2004. Most senior Canadian financial employee of Neutrino Resources Inc. (an energy company) from 1998 to 2001.	n/a	68,333

(1) Member of the Audit Committee
(2) Member of the Corporate Governance and Nominating Committee
(3) Member of the Operations Committee
(4) Including exercisable stock options

As at December 31, 2004, the directors and officers of Canada Southern, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, 285,320 Common Shares, or approximately 2.0% of the issued and outstanding Common Shares.

Executive Officers

John W.A. MacDonald, President and Chief Executive Officer

Mr. McDonald has served as President and Chief Executive Officer since April 1, 2004. Prior to joining the Company, he worked at AltaGas Services Inc. where most recently he was in charge of that company's exploration and production subsidiary. From 1989 to when he joined AltaGas in 1994, he held vice president positions in operations, supply and marketing for Western Gas Marketing Limited, a subsidiary of TransCanada Pipelines Limited. From 1971 until joining TransCanada, Mr. McDonald worked for Imperial Oil Limited/Esso Resources Canada Limited in positions of increasing responsibility dealing with corporate planning, and oil and gas production. Mr. McDonald holds Bachelor (highest distinction) and Master of Engineering degrees from Carleton University (Ottawa) and an M.B.A. from University of Toronto.

Randy L. Denecky, Chief Financial Officer

Mr. Denecky has been the Chief Financial and Accounting Officer of the Company since November 7, 2001, and the Acting President from January 7, 2002 to March 31, 2004. He is a Chartered Accountant who from 1998 to 2001 was the most senior Canadian financial employee of Neutrino Resources Inc. Mr. Denecky has 17 years of Canadian oil and gas industry experience.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

No director, officer or shareholder holding a sufficient number of securities of the Corporation is as at March 28, 2005, or within the ten years prior to March 28, 2005, has been, a director or officer or promoter of any other issuer, that while that person was acting in that capacity:

- Was the subject of a cease trade order or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days;
- Was subject to an event that resulted, after the director or executive officer ceased to be a director or executive officer, in the company being the subject of a cease trader order or similar order or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days;
- Or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was the subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets;
- Has individually, within the 10 years prior to the AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, officer or shareholder;

No director, officer or promoter of the Corporation has, within ten years prior to the date of this AIF, been subject to any penalties or sanctions imposed by a court or securities regulatory authority.

Conflicts of Interest

To our knowledge, no director or executive officer of the Corporation has an existing or potential conflict of interest with the Corporation or any of its subsidiaries, joint ventures or partnerships.

LEGAL PROCEEDINGS

Settlement of Kotaneelee Litigation

On September 9, 2003, the parties in the litigation concerning the Kotaneelee gas field entered into a comprehensive Settlement Agreement.. The settlement was finalized on October 3, 2003. Pursuant to the settlement there has been a complete abandonment of the litigation, including the claim that the defendants failed to fully develop the field.

In the third quarter of 2003, we realized a gross pre income tax amount of $23.727 million (see contingent interest litigation discussion below) in the settlement, which amount represents a complete settlement of the litigation, including a recovery of the wrongfully withheld gas processing fees and related interest. These proceeds constituted taxable income for Canadian income tax purposes upon receipt by the Company.

In connection with the settlement, we acquired on October 31, 2003, from Perkins Holdings, Ltd. and Levcor International Inc., a 0.67% carried interest in Kotaneelee formerly held by Levcor, including the associated interest in the litigation.

Also in connection with the settlement, we agreed to be responsible for our share of abandonment and reclamation liabilities at the Kotaneelee field when they occur. It is estimated that our 30.67% share of the abandonment liabilities will amount to approximately $2.4 million (undiscounted).

The settlement agreement does not include any understandings with or commitments by the working interest owners to further develop the Kotaneelee field beyond those mechanisms for doing so contained in the joint venture agreements.

Contingent Interest Settlement

In 1991 and 1997, the Company granted contingent interests in certain net recoveries from the Kotaneelee litigation. After the settlement with the defendants was agreed upon, our Board of Directors established a committee comprised solely of directors with no direct or indirect personal interest in the matter of the contingent interests. This independent committee of directors, comprised of Messrs. Kanik, McGinity and Stewart, consulted with independent outside counsel with regard to what amounts, if any, were payable pursuant to the contingent interests. In early October 2003, counsel to the independent committee advised each of the contingent interest grantees that the committee had concluded, based on advice of counsel, that there was no entitlement arising under such interests.

In March 2004, in order to avoid a potentially prolonged, expensive and distracting litigation, we reached an agreement for an all-inclusive settlement with certain parties, including a former director and former litigation counsel to the Company, who were asserting claims of entitlement against the Company’s net recoveries in the Kotaneelee litigation. Under the terms of the settlement, which had been accrued in our fourth quarter 2003 financial results, we paid these parties a total of $1 million in return for a general release from the parties asserting the claims and an agreement by us not to seek an adjustment in the prior payments for professional services made to prior litigation counsel.

In September 2004, we settled with certain former-employee contingent interest holders for $48,000.

The Company believes it has no further material exposure regarding this matter.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

To the best of our knowledge, the Corporation confirms that, as of March 28, 2005, there were no directors or executive officers of the Corporation or an associate or affiliate of a director or executive officer of the Corporation with a material interest in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect the Corporation.

TRANSFER AGENT, REGISTRAR, AND TRUSTEES

The transfer agent and registrar for the Corporation's Common Shares is:

American Stock Transfer and Trust Company
59 Maiden Lane
Plaza Level
New York, NY 10038

Tel (800) 937-5449
Tel (718) 921-8124
Fax (718) 236-2641
Email: (via website)
Website: www.amstock.com

Computershare Trust Company of Canada
530 - 8th Avenue S.W.
Calgary, AB T2P 3S8
Canada
Telephone: (403) 267-6800
Email: webservice@computershare.com
Website: www.computershare.com

EXPERTS

Names of Experts

Our consolidated financial statements for the year ended December 31, 2004 included in our 2004 Annual Report filed under National Instrument 51-102 Continuous Disclosure (NI 51-102), portions of which are incorporated by reference to this AIF, have been audited by Ernst & Young LLP.

Interests of Experts

As of March 28, 2005, Ernst & Young LLP and the partners of Ernst & Young LLP do not hold any registered or beneficial ownership directly or indirectly in the securities of the Corporation or its associates or affiliates.

AUDIT COMMITTEE

Audit Committee Charter

Attached as Schedule 16.1 is our Audit Committee charter.

Composition of the Audit Committee

Members of the Audit Committee are Richard C. McGinity (Chair), Raymond P. Cej, Myron F. Kanik and Arthur B. O'Donnell. Each member of the Audit Committee is independent and financially literate.

Relevant Education and Experience of Members of the Audit Committee

Audit Committee Member	Relevant Education and Experience
Richard C. McGinity (Chair)	Since 1986, Mr. McGinity has been President of School Street Capital Group, an investment banking firm, advising private companies seeking expansion financing or mergers and acquisition services. Mr. McGinity has a Doctorate in Business Administration from the Harvard Business School.
Raymond P. Cej	Mr. Cej has been President since 2002 of BA Energy Ltd. (an oilsands energy company). From 2001 to 2003 Mr. Cej was President of Synenco Energy Inc. (an oilsands energy company). From 1998 to 2001 Mr. Cej served as President and Chief Executive Officer with international and domestic oil and gas production and service companies. Prior to 1995, Mr. Cej was Senior Operating Officer of Shell Canada Resources, a division of Shell Canada Ltd. (an energy company).
Myron F. Kanik	Mr. Kanik is President of Kanik and Associates Ltd., a consulting firm. From 1993 to 1999 he was President of the Canadian Energy Pipeline Association and was Deputy Minister for the Alberta Department of Energy from 1985 to 1993.
Arthur B. O'Donnell	Mr. O'Donnell served as a senior accounting and financial officer of the Company prior to his retirement in 1994. Mr. O'Donnell is a Certified Public Accountant.

Pre-Approval Policies and Procedures

Under the terms of the Audit Committee Charter, the Audit Committee is required to pre-approve all the services provided by, and fees and compensation paid to, the independent auditors for both audit and permitted non-audit services. When it is proposed that the independent auditors provide additional services for which advance approval is required, the Audit Committee may form and delegate authority to a subcommittee consisting of one or more members, when appropriate, with the authority to grant pre-approvals of audit and permitted non-audit services, provided that decisions of such subcommittee to grant pre-approvals are to be presented to the Committee at its next scheduled meeting.

External Auditor Service Fees (By Category)

The following table sets out the fees billed to us by Ernst & Young LLP and its affiliates for professional services in each of the years ended December 31, 2004 and 2003. During these years, Ernst & Young LLP was our only external auditor.

	Years Ended December 31,	
Category	**2004**	**2003**
Audit Fees(1)	$ 110,000	$ 103,138
Audit-Related Fees(2)	4,500	6,690
Tax Fees(3)	37,167	82,830
All Other Fees(4)	-	-
Total	$ 151,667	$ 192,658

(1) For professional services rendered by Ernst & Young LLP for the audit and review of our financial statements or services that are normally provided by Ernst & Young LLP in connection with statutory and regulatory filings or engagements.
(2) For assurance and related services by Ernst & Young LLP that are reasonably related to the performance of the audit or review of our financial statements and are not reported under "Audit Fees" above.
(3) For professional services rendered by Ernst & Young LLP for tax compliance, tax advice and tax planning.
(4) For services provided by Ernst & Young LLP other than the services reported under "Audit Fees", "Audit-Related Fees" and "Tax Fees" above.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities, options to purchase securities and interest of insiders in material transactions, where applicable, is provided in our management proxy circular for our most recent annual meeting of shareholders that involved the election of directors, and additional financial information as provided in our consolidated financial statements for our most recently completed financial year.

We will provide to any person, upon request made to the Corporate Secretary of Canada Southern Petroleum Ltd., Suite 250, 706 - 7th Avenue S.W., Calgary, AB T2P 0Z1:

(a) When securities of the Corporation are in the course of a distribution pursuant to a short form prospectus or a preliminary short form prospectus has been filed and respecting a distribution of its securities;

  (i) one copy of this annual information form, together with one copy of any document, or the pertinent pages of any document, incorporated by reference herein;

  (ii) one copy of our consolidated financial statements for our most recently completed financial year, together with the accompanying report of our auditor, and one copy of any of our interim financial statements subsequent to the financial statements for our most recently completed financial year;

  (iii) one copy of our management proxy circular with respect to our most recent annual meeting of shareholders that involved the election of directors; and

  (iv) one copy of any documents that are incorporated by reference into the preliminary short form prospectus or the short form prospectus and are not required to be provided under items (i) to (iii) above; or

(b) at any time, one copy of any other documents referred to in items (a), (i), (ii) and (iii) above.

Additional information relating to Canada Southern may be found on our website at http://www.cansopet.com, on the Canadian Securities Administrators' website at www.sedar.com and on the EDGAR section of the U.S. Securities and Exchange Commission's website at www.sec.gov.

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Canada Southern Petroleum Ltd. (the "Company") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2004 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at December 31, 2004 using constant prices and costs; and

(ii) the related estimated future net revenue.

Gilbert Laustsen Jung Associates Ltd., an independent qualified reserves evaluator, has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Board of Directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Board of Directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has approved

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

by /s/ John W. A. McDonald
John W. A. McDonald
President and Chief Executive Officer

by /s/ Randy L. Denecky
Randy L. Denecky
Chief Financial Officer

by /s/ Myron F. Kanik
Myron F. Kanik
Director

by /s/ Raymond P. Cej
Raymond P. Cej
Director

REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR OR AUDITOR

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2004. The reserves data consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2004, using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) proved oil and gas reserves estimated as at December 31, 2004, using constant prices and costs; and

   (ii) the related estimated future net revenue.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2004, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate M$)			
		Audited	Evaluated	Reviewed	Total
March 8, 2005	Canada	-	$23,537	-	$23,537

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

6. We have no responsibility to update this evaluation for events and circumstances occurring after the preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:
Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta, Canada

Dated March 17, 2005

Keith M. Braaten, P. Eng.
Vice-President

Schedule 16.1

CANADA SOUTHERN PETROLEUM LTD.
Audit Committee Charter
(Originally adopted January 28, 2000,
revised February 26, 2004)

1. This charter (the "Charter") governs the operations of the audit committee (the "Committee") of the board of directors (the "Board") of Canada Southern Petroleum Ltd. (the "Company").

Purpose of the Audit Committee

2. The Committee shall assist the Board in fulfilling its oversight responsibility relating to the Company's financial statements and the financial reporting process, the systems of internal accounting and financial controls, and the annual independent audit of the Company's financial statements. In performing its duties, it is the responsibility of the Committee to maintain free and open communication between the directors, the Company's independent audit firm (the "Outside Auditor") and the financial management of the Company.

Composition of the Committee

3. The Committee shall be comprised of three or more directors as determined by the Board, each of whom shall: (c) satisfy the independence and experience requirements of any applicable U.S. or Canadian Federal, state or provincial securities and corporate laws and regulations and the listing standards of each securities exchange on which the Company's securities are traded (together, "Applicable Law"); and (d) be free from any relationship which, in the opinion of the Board of Directors, would interfere with the exercise of his or her independent judgment as a member of the Committee.

4. All members of the Committee at the time of their appointment to the Committee must be able to read and understand financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Company's financial statements, and at least one member will have accounting or related financial management expertise which results in the member's financial sophistication. To the extent required by Applicable Law, or, if not required to the extent reasonably feasible, at least one member of the Committee shall qualify as an "audit committee financial expert" as defined by Applicable Law, as determined annually by the Board.

5. Appointment to the Committee, the determination of the "independence" of each Committee member, and the designation of one or more Committee members as an "audit committee financial expert," shall be made on an annual basis by the Board. The Board shall also fill any vacancies as they occur and may remove any member at any time. Unless a Chair is appointed by the Board, the members of the Committee may designate a Chair by majority vote of the Committee.

Meetings; Organization

6. The Committee shall meet at least four times annually, or more frequently as the Chair or the Committee deems appropriate, or at the request of the Company's Outside Auditor. As part of its responsibilities to foster open communication, the Committee should meet at least annually with management and with the Outside Auditor in separate executive sessions to discuss any matters that the Committee or each of these groups believe should be discussed privately. The Committee may ask members of management, legal counsel, representatives of the Outside Auditor or others to attend its meetings or provide information.

7. The Committee shall be subject to the provisions of the Company's Articles of Association. The Committee is authorized and empowered to adopt its own rules of procedure not inconsistent with (e) this Charter; (f) the Articles of Association or (g) Applicable Law.

8. The Committee shall keep minutes of each meeting, which shall be approved by the Committee members and shall be given to the corporate Secretary for filing with the corporate records. The Committee shall also submit the minutes of all meetings of the Committee to, or discuss the matters discussed at each Committee meeting with, the full Board. The Chairman shall report to the Board from time to time and as requested by the Board.

Committee Authority and Responsibilities

9. In assisting the Board in its oversight role, the Committee shall have full access to all books, records, facilities, and personnel of the Company and shall have the sole authority, to the extent it deems necessary or appropriate, to retain special legal, accounting or other consultants and approve their retention terms. The Company shall provide appropriate funding, as determined by the Committee, for payment of compensation to the Outside Auditor for the purpose of rendering or issuing an audit report or related work and to any outside advisors employed by the Committee.

10. In carrying out its responsibilities, the Committee believes its policies and procedures should remain flexible, in order to best react to changing conditions and to ensure to the directors and shareholders that the accounting and reporting practices of the Company are in accordance with all requirements and are of the highest quality. In carrying out these responsibilities, the Committee shall, to the extent it deems necessary and appropriate, perform the following functions:

(a) The Committee shall have a clear understanding with management and the Outside Auditor that the Outside Auditor is accountable to the Committee and to the Board, as representatives of the Company's shareholders. The Committee shall have the sole authority and responsibility to select (and, if required by Applicable Law, recommend to the Company's shareholders for approval), evaluate and, where appropriate, replace the Outside Auditor. The Committee shall be directly responsible for approving the level of compensation of the Outside Auditor and the oversight of the work of the Outside Auditor (including resolution of disagreements between management and the Outside Auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or related work. The Outside Auditor shall report directly to the Committee.

(b) The Committee shall annually review and evaluate the qualifications, performance and independence of the lead partner of the Outside Auditor and assure regular rotation of the lead audit partner and reviewing partner as required by Applicable Law and evaluate the appropriateness of rotating the independent audit firm and provide its conclusions to the Board.

(c) The Committee shall preapprove all auditing services and permitted non-audit services (including the fees and terms thereof) to be performed for the Company by the Outside Auditor, subject to the de minimis exceptions for non-audit services described in Applicable Law which are approved by the Committee prior to the completion of the audit. The Committee may form and delegate authority to subcommittees consisting of one or more members when appropriate, including the authority to grant preapprovals of audit and permitted non-audit services, provided that decisions of such subcommittee to grant preapprovals shall be presented to the Committee at its next scheduled meeting.

(d) On an annual basis, the Committee shall obtain from the Outside Auditor a written communication delineating all their relationships and professional services as required by Applicable Law regarding the independence of auditors. In addition, the Committee shall review with the Outside Auditor the nature and scope of any disclosed relationships or professional services and take any appropriate action to ensure the continuing independence of the Outside Auditor.

(e) The Committee shall meet with the Outside Auditor and management of the Company to review the scope of the proposed audit and timely quarterly reviews for the current year and the procedures to be utilized, the adequacy of the Outside Auditor's compensation, and at the conclusion thereof review such audit or review, including any comments or recommendations of the Outside Auditor.

(f) The Committee shall meet regularly with the Outside Auditor without members of management present. Among the items to be discussed in these meetings are the Outside Auditor' evaluation of the Company's financial, accounting, and auditing personnel, and the cooperation that the Outside Auditor received during the course of audit.

(g) The Committee shall review with the Outside Auditor and management the adequacy and effectiveness of the accounting and internal controls over financial reporting of the Company, and elicit any recommendations for the improvement of such internal controls or particular areas where new or more detailed controls or procedures are desirable. Particular emphasis should be given to the adequacy of internal controls to expose any payments, transactions, or procedures that might be deemed illegal or otherwise improper. The Committee shall also review and discuss with management and the Outside Auditors (i) the annual report prepared by management with respect to the Company's internal control over financial reporting and (ii) the attestation report pertaining thereto to be delivered by the Outside Auditor. The Committee shall also obtain from the Outside Auditor periodic assurances that the Outside Auditor is complying with all provisions of Applicable Law which require the Outside Auditor, if it detects or becomes aware of any illegal act, to assure that the Committee is adequately informed and to provide a report if the Outside Auditor has reached specified conclusions with respect to such illegal acts.

(h) The Committee shall discuss in advance with management the Company's practices with respect to the types of information to be disclosed and the types of presentations to be made in earnings press releases, including the use of "pro forma" or "adjusted" non-GAAP information (if any), and financial information and earnings guidance; and shall also discuss with management and the Outside Auditors the effect of off-balance sheet structures, if any, and aggregate contractual obligations on the Company's financial statements.

(i) The Committee shall review the Company's financial statements, management's discussion and analysis and earnings press releases before the Company publicly discloses this information.

(j) The Committee shall review and discuss the quarterly financial statements with financial management and the Outside Auditor prior to the filing under Applicable Law of any reports or information with respect thereto (and prior to the press release of results, if possible) to determine that the Outside Auditor does not take exception to the disclosure and content of the financial statements, and shall also discuss any other matters required to be communicated to the Committee by the Outside Auditor under generally accepted accounting standards. The Chair of the Committee may represent the entire Committee for purposes of this review.

(k) The Committee shall review and discuss with management and the Outside Auditor the financial statements to be included in the Company's annual disclosure documents, to determine that the Outside Auditor is satisfied with the disclosure and content of the financial statements to be presented to the shareholders. The Committee shall also review and discuss with financial management and the Outside Auditor: (h) the results of their timely analysis of significant financial reporting issues and practices including changes in, or adoptions of, accounting principles and disclosure practices; (i) the Outside Auditor's judgment about the quality, not just the acceptability, of accounting principles and the clarity of the financial disclosure practices used or proposed to be used, and particularly, the degree of aggressiveness or conservatism of the Company's accounting principles and underlying estimates, and other significant decisions made in preparing the financial statements; (j) any matters required to be communicated to the Committee by the Outside Auditor under generally accepted auditing standards, or (k) any other reports of the Outside Auditor required by law or professional auditing standards, including reports on: critical accounting policies and practices used in preparing the financial statements; alternative treatments of financial information discussed with management, ramifications of such alternative disclosures and treatments, and the treatment preferred by the Outside Auditors; and other significant written communications between the Outside Auditors and the management of the Company, such as any management letter issued or proposed to be issued, and a schedule of unadjusted differences, if any.

(l) The Committee must be satisfied that adequate procedures are in place for the review of the Company's disclosure of financial information extracted or derived from the Company's financial statements, other than the disclosure referred to in subsection (i), and must periodically assess the adequacy of those procedures.

(m) The Committee must review and approve the Company's hiring policies regarding employees and former employees of the present and former Outside auditors.

(n) The Committee shall report the results of the annual audit to the Board, and if requested by the Board, invite the Outside Auditor to attend the Board meeting to assist in reporting the results of the annual audit or to answer other directors' questions (alternatively, the other directors, particularly the other independent directors, may be invited to attend the Committee meeting during which the results of the annual audit are reviewed).

(o) The Committee shall review disclosures, if any, made by the Company's Chief Executive Officer and Chief Financial Officer during their certification process for the Company's periodic reports regarding: 1.1.1.1 all significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information; and 1.1.1.2 any fraud, whether or not material, that involves management or other employees who have a role in the Company's internal controls over financial reporting.

(p) To the extent required by Applicable Law, the Committee shall prepare and publish a Committee report for inclusion in the Company's annual proxy statement and provide any additional disclosures in the proxy statement or the Company's disclosure documents.

(q) The Committee shall review reports received from regulators and other legal and regulatory matters that may have a material effect on the financial statements or related Company compliance policies.

(r) The Committee shall inquire of management and the Outside Auditor about significant risks or exposures and assess the steps management has taken to minimize such risks to the Company.

(s) The Committee shall review accounting and financial human resources and succession planning within the Company.

(t) To the extent required by Applicable Law, the Committee shall review and approve any "related-party" transactions involving the Company and officers, directors or shareholders beneficially owning more than 10% of any class of equity security of the Company.

(u) The Committee shall investigate any matter brought to its attention within the scope of its duties, with the power to retain outside counsel for this purpose if, in its judgment, that is appropriate.

(v) The Committee shall perform any other duties consistent with this Charter, the Articles of Association and Applicable Law as the Committee or the Board deems necessary.

(w) The Committee shall obtain Board approval of this Charter, shall annually review and reassess the adequacy of this Charter as conditions dictate, and shall publish the Charter as required by Applicable Law.

(x) The Committee shall also annually review the Committee's own performance and present a report to the Board of the performance evaluation of the Committee.

Receipt and Treatment of Complaints

11. The Committee shall establish and oversee procedures for: the receipt, retention, and treatment of complaints received by the Company regarding accounting, internal accounting controls, auditing, or other matters; and the confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting, internal accounting controls or auditing matters.

Limitation of Committee's Role

12. While the Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Committee to plan or conduct audits or to determine that the Company's financial statements and disclosures are complete, and accurate and are in accordance with generally accepted accounting principles and applicable rules and regulations. Management is responsible for the financial reporting process, including the system of internal controls, and for the preparation of consolidated financial statements in accordance with generally accepted accounting principles. The Company's Outside Auditor is responsible for auditing those financial statements and expressing an opinion as to their conformity with generally accepted accounting principles. The Committee's responsibility is to oversee and review these processes. The members of the Committee are not, however, professionally engaged in the practice of accounting or auditing and do not provide any expert or other special assurance as to such financial statements concerning compliance with laws, regulations or generally accepted accounting principles or as to auditor independence. Each member of the Committee shall be entitled to rely on information, opinions, reports or statements, including financial statement and other financial data prepared or presented by officers and employees of the Company, legal counsel, the Outside Auditor or other persons with professional or expert competence.