



**ANNUAL INFORMATION FORM  
FOR THE YEAR ENDED DECEMBER 31, 2007**

**March 26, 2008**

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## FORWARD LOOKING INFORMATION

Certain information in this Annual Information Form is "forward looking information". Forward looking information is frequently characterized by words such as "plan", "expect", "project", "intend", "believe", "anticipate", "estimate" or other similar words, or statements that certain events or conditions "may" or "will" occur. Forward looking information involves significant known and unknown risks and uncertainties. A number of factors, many of which are beyond the control of the Corporation could cause actual results to differ materially from the results discussed in the forward looking information. Although the forward looking information contained in this Annual Information Form is based upon assumptions which Management believes to be reasonable, the Corporation cannot assure investors that actual results will be consistent with this forward looking information. The forward looking information contained herein is made as of the date of this Annual Information Form, and the Corporation assumes no obligation to update or revise it to reflect new events or circumstances, except as required by law. Because of the risks, uncertainties and assumptions inherent in forward looking information, prospective investors in the Corporation's securities should not place undue reliance on this forward looking information.

In particular, this Annual Information Form contains forward looking information pertaining to the following:

- expectations regarding ramping up of production from Pod One;
- expectations regarding the commencement of construction of the Algar Project;
- the quantum of, and future net revenues from, the crude oil, natural gas and bitumen reserves and resources;
- expectations regarding throughput from the Corporation's refinery in Great Falls, Montana;
- crude oil, natural gas and bitumen production levels;
- expectations regarding future developments costs and the ability to fund such costs;
- expectations regarding the timing of developing the Corporation's undeveloped reserves;
- expectations regarding the effective date of the Canadian Federal Government's new regulations regarding air emissions;
- projections of market prices and costs; and
- expectations regarding capital expenditures and exploration activities and the timing and funding in respect thereof.

With respect to forward looking information contained in this Annual Information Form, the Corporation has made assumptions regarding, among other things:

- future prices for crude oil, natural gas, bitumen and refined products;
- future currency and interest rates;
- the Corporation's ability to generate sufficient cash flow from operations and access existing credit facilities and capital markets to meet its future obligations;
- the regulatory framework representing royalties, taxes and environmental matters in the provinces of Canada in which the Corporation conducts its business; and
- the Corporation's ability to obtain qualified staff and equipment in a timely and cost-efficient manner to meet the Corporation's demand.

Some of the risks that could affect the Corporation's future results and could cause results to differ materially from those expressed in the Corporation's forward looking statements include:

- the need to obtain required approvals and permits from regulatory authorities;

- the impact of competition;
- compliance with and liabilities under environmental laws and regulations;
- the uncertainties of estimates by the Corporation's independent consultants with respect to the Corporation's reserves and resources;
- the volatility of crude oil, natural gas, bitumen and refined product prices;
- general economic conditions in Canada;
- changes to royalty regimes and government regulations regarding royalty payments;
- risks associated with exploring for, developing, producing, processing, storing and transporting crude oil, bitumen and natural gas;
- risks associated with the operation of a refinery;
- geological, technical, drilling and processing problems;
- the Corporation's ability to hire and retain staff;
- imprecision in estimating capital expenditures and operating expenses;
- imprecision in estimating the timing, costs and levels of production and drilling;
- imprecision in estimating the timing, costs and levels of throughput related to the Corporation's refinery and any expansion thereof;
- imprecision in estimates of future production capacity;
- potential delays or changes in plans with respect to exploration and development projects or capital expenditures;
- changes to regulations and legislation applicable to Connacher and the interpretation thereof including tax and environmental legislation and regulations in the provinces of Canada in which the Corporation conducts its business;
- general economic and business conditions;
- unavailability of required equipment and services; and
- the other factors discussed under "Risk Factors".

Statements relating to "reserves" and "resources" are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the described reserves and resources, as the case may be, exist in the quantities predicted or estimated, and can be profitably produced in the future. The assumptions relating to the reserves and resources of the Corporation are discussed under "Oil, Natural Gas and Bitumen Reserves" and "Bitumen Resources", respectively.

## ABBREVIATIONS AND DEFINITIONS

In this Annual Information Form, the abbreviations set forth below have the following meanings:

"bbl"	barrels	"mcf/d"	1,000 standard cubic feet per day
"bbl/d"	barrel or barrels per day	"mcf"	One thousand cubic of feet natural gas equivalent
"boe"	Barrels of oil equivalent	"mmcf"	1,000,000 cubic feet
"boe/d"	Barrel or barrels of oil equivalent per day	"mmcf/d"	1,000,000 cubic feet per day
"M\$"	means thousands of Canadian dollars	"mmbtu"	1,000,000 British thermal units
"mdbl"	1,000 barrels	"NGL"	Natural gas liquids
"mcf"	1,000 cubic feet		

**Note:** For the purposes of this document, 6 mcf of natural gas and 1 bbl of NGL each equal 1 bbl of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an

energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

"**1P**" means the proved reserve category as defined in the COGE Handbook;

"**2P**" means the proved and probable reserve categories as defined in the COGE Handbook;

"**3P**" means the proved, probable and possible reserve categories as defined in the COGE Handbook;

"**ABCA**" means the *Business Corporations Act* (Alberta), S.A. 2000, c. B-9, together with any amendments thereto and all regulations promulgated thereunder;

"**Algar Project**" means the Algar project, the Corporation's second planned 10,000 bbl/d SAGD bitumen facility and wells located at Great Divide;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining Metallurgy & Petroleum (Petroleum Society);

"**Common Shares**" or "**Connacher Shares**" means the common shares in the share capital of the Corporation;

"**Connacher**" or the "**Corporation**" means Connacher Oil and Gas Limited and its subsidiaries, unless the context otherwise requires;

"**Connacher GLJ Report**" means the independent engineering evaluation of the crude oil, bitumen and natural gas interests of the Corporation prepared by GLJ Petroleum Consultants Ltd. ("**GLJ**"), independent petroleum engineering consultants of Calgary, Alberta, dated February 28, 2008 and effective December 31, 2007;

"**Contingent Resources**" means those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies;

"**Great Divide**" means the Divide area located in northeastern Alberta where the Corporation's Pod One and Algar projects are located;

"**Holly**" means Holly Corporation;

"**Luke**" means Luke Energy Ltd.;

"**Luke Acquisition**" means the acquisition by Connacher of all the outstanding common shares of Luke by way of a business combination under a plan of arrangement;

"**Luke Shares**" means the common shares in the share capital of Luke;

"**MRC**" means Montana Refining Company, Inc. (a wholly-owned subsidiary of the Corporation);

"**MRC Acquisition**" means the acquisition by Connacher of an 8,300 bbl/d refinery and related inventory situated in Great Falls, Montana operated by Holly's Montana Refinery Company;

"**Management**" means management of the Corporation;

"**NI 51-101**" means National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities*;

"**Petrolifera**" means Petrolifera Petroleum Limited;

"**Petrolifera AIF**" means the annual information form of Petrolifera for the year ended December 31, 2007 dated March 26, 2008;

"**Petrolifera GLJ Report**" means the independent engineering evaluation of the crude oil, natural gas liquids and natural gas interests of Petrolifera prepared by GLJ, independent petroleum engineering consultants of Calgary, Alberta, dated March 3, 2008 and effective December 31, 2007;

"**Prospective Resources**" means those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects;

"**Puesto Morales Concession**" or "**Concession**" means the interests in the Puesto Morales and Rinconada blocks in the Neuquén Basin in Argentina;

"**Pod One**" means the Corporation's existing 10,000 bbl/d SAGD bitumen facility and wells project located at Great Divide;

"**Refinery**" means the refinery and related inventory located in Great Falls, Montana acquired by the Corporation pursuant to the MRC Acquisition;

"**SAGD**" means steam-assisted gravity drainage;

"**SOR**" means steam-oil ratio;

"**Sayer Energy Advisors Report**" means the independent evaluation of the Canadian undeveloped land acreage of the Corporation prepared by Sayer Energy Advisors ("**Sayer**"), independent oil and gas advisory firm of Calgary, Alberta, dated February 14, 2008 and effective December 31, 2007; and

"**TSX**" means the Toronto Stock Exchange.

In this Annual Information Form, references to "dollars" and "\$" are to the currency of Canada, unless otherwise indicated.

## THE CORPORATION

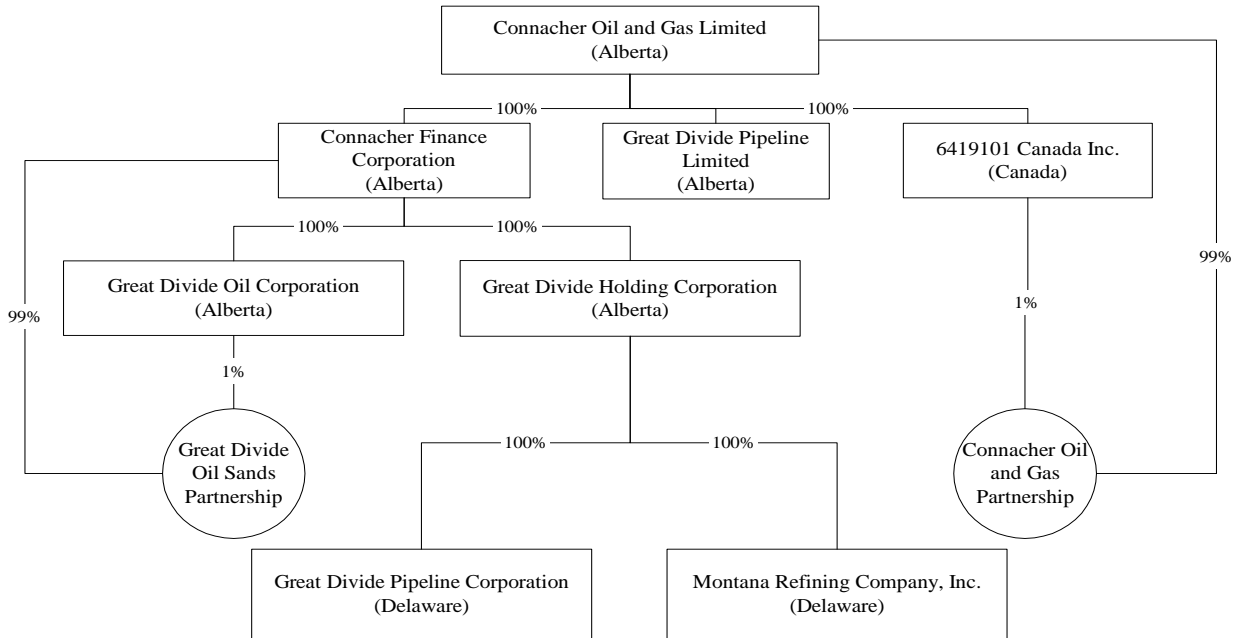
### Incorporation and Organization

The Corporation was formed on July 3, 1997 through the amalgamation pursuant to the ABCA of Petro Power Energy Inc. and Justinian Explorations Ltd. and continued as Justinian Explorations Ltd., a public corporation listed on the TSX Venture Exchange. On January 23, 2001 the outstanding Connacher Shares were consolidated on a ten-for-one basis and the name of the Corporation was changed to Connacher Oil and Gas Limited. Trading in the Connacher Shares under the symbol "CLL" commenced on the TSX Venture Exchange on March 23, 2001. This listing was surrendered on August 1, 2003 when the Corporation graduated to and commenced trading on the TSX.

As of December 31, 2007, the Corporation had seven wholly-owned subsidiaries, 6419101 Canada Inc., a corporation incorporated under the *Canada Business Corporations Act*, Great Divide Oil Corporation, Connacher Finance Corporation, Great Divide Pipeline Limited and Great Divide Holding Corporation, all of which are corporations incorporated under the ABCA and Great Divide Pipeline Corporation and Montana Refining Company, Inc. both of which are organized pursuant to the laws of the State of Delaware. The Corporation also has a significant equity interest in Petrolifera. See "Business of the Corporation - Ownership of Petrolifera".

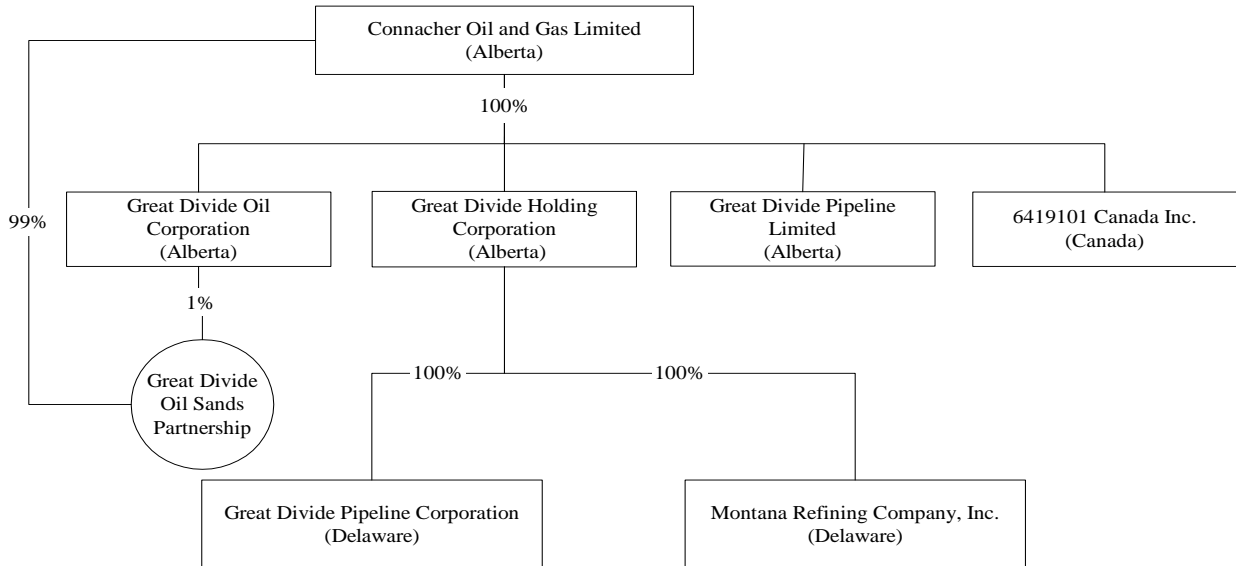
The Corporation has its head and principal office at Suite 900, 332 – 6th Avenue S.W., Calgary, Alberta, T2P 0B2 and its registered office at 3700, 400 Third Avenue S.W., Calgary, Alberta, T2P 4H2.

The following chart illustrates the Corporation's organizational structure as at December 31, 2007:



On January 1, 2008 Connacher amalgamated with Connacher Finance Corporation pursuant to the ABCA. On January 31, 2008 the Connacher Oil and Gas Partnership was dissolved pursuant to the *Partnership Act* (Alberta).

The following chart illustrates the Corporation's organizational structure as of the date of this Annual Information Form:



### General Development of the Corporation

Connacher is primarily engaged in the exploration for, and the development, production and refining of, crude oil and the exploration, development and production of natural gas. The Corporation's principal asset is a 100

percent working interest in approximately 98,000 acres of oil sands leases in the Divide and Halfway Creek regions near Fort McMurray, Alberta. The Corporation has commenced production from its first 10,000 bbl/d SAGD project at Great Divide, referred to herein as Pod One, and has made regulatory application for its second 10,000 bbl/d oil sands project at Great Divide, referred to as the Algar Project. The Corporation also owns producing crude oil and natural gas properties at Battrum, Saskatchewan and at Marten Creek and Three Hills, Alberta, a 9,500 bbl/d refinery located in Great Falls, Montana and a 26 percent equity interest in Petrolifera, a public Canadian oil and natural gas company active in Argentina, Peru and Colombia. The following is a general description of the development of the Corporation over the past three years.

In September 2005, Connacher completed a public financing on a "bought-deal" basis of 27,027,400 Connacher Shares at a price of \$1.85 per share. An additional 13,513,600 Connacher Shares were issued to the underwriters in connection with such financing upon exercise of their over-allotment option for total gross proceeds of \$75,000,850. Proceeds from the financing were used to fund exploration and development of Connacher's Great Divide oil sands leases and for general corporate purposes.

Petrolifera completed an initial public offering of its common shares and warrants in November 2005. Following completion of the initial public offering (and after giving effect to Connacher's investment of \$6 million in securities offered pursuant to the initial public offering), Connacher held an undiluted 35 percent equity interest (26 percent equity interest on a fully-diluted basis) in Petrolifera, reduced from a 40 percent equity interest Connacher held in Petrolifera prior to completion of the initial public offering and a 61 percent equity interest as at December 31, 2004.

In December 2005, Connacher completed the sale to a syndicate of underwriters of 5,000,000 flow-through Common Shares at a price of \$3.00 per share. Net proceeds from this financing were used by Connacher to incur eligible Canadian exploration expenses and, in that regard, primarily to further delineate and define Connacher's Great Divide oil sands properties through the drilling of additional core holes and shooting additional 3D seismic.

In December 2005, Connacher and Luke entered into a binding letter agreement pursuant to which Connacher agreed to acquire the outstanding common shares of Luke by way of a business combination under a proposed plan of arrangement.

Also, in December 2005, Connacher entered into an exclusivity agreement with the Montana Refining Company, a subsidiary of Holly, to negotiate the terms of a purchase and sale agreement to acquire an 8,300 bbl/d refinery, together with related structures and specified tangible assets situated in Great Falls, Montana.

Throughout 2005, a total of 3,791,705 Common Share purchase warrants and broker warrants and 981,000 stock options were exercised, resulting in the Corporation receiving cash proceeds of \$2,652,296.

In February 2006, Connacher, Luke and 6492894 Canada Inc. entered into an arrangement agreement that set out the terms pursuant to which Connacher was to complete the Luke Acquisition. The Luke Acquisition was completed in March 2006 resulting in the payment of approximately \$91.5 million and the issuance from treasury of approximately 30 million Connacher Shares to Luke shareholders.

In February 2006, Connacher completed a "bought-deal" private placement financing of 8,571,500 Common Shares at a price of \$5.25 per share. An additional 10,476,300 Common Shares were issued to the underwriters in connection with the financing upon exercise of their over-allotment option for total gross proceeds of \$100,000,950. Proceeds from the financing were used to fund Connacher's exploration and development activities, for general corporate purposes and for working capital.

In March 2006, MRC signed an asset purchase agreement pursuant to which it completed the MRC Acquisition. The MRC Acquisition was completed on March 31, 2006. The consideration for the purchase was US\$55 million, comprised of cash and one million Connacher Shares from treasury. For further details with respect to the MRC Acquisition, reference should be made to the business acquisition report of the Corporation dated June 14, 2006, which is posted on SEDAR ([www.sedar.com](http://www.sedar.com)) and is not incorporated by reference in this Annual Information Form.

In June 2006, Connacher received a letter from the Alberta Energy and Utilities Board approving the Corporation's Pod One oil sands project. In July 2006, Connacher was granted an Order in Council approving its Pod One oil sands project, representing the last formal approval requirement for the project to proceed.

In September 2006, Connacher completed a "bought-deal" financing of 5,000,000 flow-through common shares at a price of \$5.25 per flow-through share. An additional 714,300 flow-through shares were issued to the underwriters in connection with the financing upon exercise of their over-allotment option for total gross proceeds of \$30,000,075. Proceeds from the financing were used to fund exploration activities including the further delineation of the Corporation's oil sands properties at Great Divide.

In October 2006, Connacher completed a long term debt financing comprised of a US\$180 million Term Loan B Facility (the "**TLB Facility**") and US\$15 million Working Capital Facility (the "**WC Facility**") (collectively, the "**Facilities**"). The Facilities were syndicated to institutional investors located primarily in the United States and in Canada. The proceeds of the TLB Facility were used to discharge short-term indebtedness of US\$51 million incurred in the MRC Acquisition, fund a one year debt service reserve during the construction phase of Pod One and pay expenses associated with the long-term debt financing. The balance of approximately US\$111 million of the proceeds was added to cash working capital and was used to finance the remaining construction and related capital expenditures of Pod One. The WC Facility was used to fund ongoing working capital requirements at the Refinery.

Throughout 2006, a total of 1,493,820 Common Share purchase warrants and 998,365 stock options were exercised, resulting in the Corporation receiving cash proceeds of \$1,898,000.

During the first quarter of 2007 Connacher advanced its development and construction program at Pod One, which included residual site preparation, construction of the main processing plant and drilling of horizontal well pairs in preparation for the commencement of operations.

In May 2007, Connacher completed a "bought-deal" financing for \$87,000,000 aggregate principal amount of convertible senior unsecured debentures due June 30, 2012. An additional \$13,050,000 aggregate principal amount of debentures were issued to the underwriters in connection with such financing upon exercise of their over-allotment option for total gross proceeds of \$100,050,000. Proceeds of the offering were used by the Corporation to repay short term borrowings and to fund capital expenditure programs in respect of the development of its oil sands projects and conventional projects and the remainder was used for operating expenses.

In June 2007, Connacher submitted an application to the Alberta Energy and Utilities Board and other related regulators and government departments for approval to proceed with the development of the Algar Project.

Connacher completed construction of the Pod One SAGD facility and drilling of the related well pairs in August 2007. The plant was commissioned and on September 16, 2007, steaming of the well pairs commenced. On October 22, 2007 Connacher announced that it had delivered and sold to market its first truckload of diluted bitumen from Pod One.

On October 25, 2007, the Government of Alberta unveiled a new proposed royalty regime. The new regime would introduce new royalties for conventional oil, natural gas and oil sands effective January 1, 2009 that are linked to price and production levels and would apply to both new and existing oil sands projects. See "Risk Factors".

In November 2007, Connacher completed a "bought-deal" financing of 9,000,000 flow-through common shares at a price of \$5.00 per flow-through share. An additional 1,350,000 flow-through shares were issued to the underwriters in connection with the financing upon exercise of an over-allotment option. Furthermore, Connacher also issued an aggregate of 100,000 flow-through shares at a price of \$5.00 per flow-through share pursuant to a private placement. The total gross proceeds of \$52,250,000 from the financings have been used to drill exploratory core holes and conduct 3D seismic to assist in the delineation of additional oil sands reserves and resources at Great Divide and Halfway Creek.

In December 2007, Connacher completed the sale of US\$600 million aggregate principal amount of 10.25 percent senior secured second lien notes (the "**Notes**") due December 15, 2015, at a price of 98.657 percent resulting

in a yield to maturity of 10.50 percent and gross proceeds of approximately US\$592 million (approximately C\$592 million). A portion of the proceeds was used to discharge Connacher's outstanding indebtedness (including the TLB Facility and the WC Facility), to fund a one-year debt service reserve account and to pay certain expenses associated with the issuance of the Notes. The balance of approximately C\$327 million was added to the Corporation's working capital and is available to fully fund the construction of the Algar Project.

Coincidental with the sale of the Notes, Connacher secured a new syndicated five year term revolving first lien credit facility (the "**Revolving Facility**"). The Revolving Facility is comprised of a C\$150 million tranche and a US\$50 million tranche, with the latter for use in the business of the Refinery.

Throughout 2007, a total of 1,518,267 stock options were exercised, resulting in the Corporation receiving cash proceeds of \$1,466,000. In addition, 108,975 Common Shares were issued in 2007 pursuant to the Corporation's share award incentive plan for non-employee directors.

## **Trends**

There are some trends that have been developing in the oil and gas industry during the past two years.

The first trend is the consolidation that the industry has been experiencing. Consolidation has affected companies of all sizes from the small emerging companies to the senior integrated companies, and more recently the oil and gas trusts. Because of the relatively high commodity prices in the industry in recent history and the increased demand for producing properties, the trend in the industry is for larger entities to continue to acquire smaller entities. To date, oil and gas royalty trusts have also been a significant acquirer of producing oil and gas properties and companies and more recent trends have seen a significant consolidation in the trust sector. However, recent legislative changes to the taxation of trusts have affected this trend.

The second trend is the significant access to external capital that the industry has been experiencing. Oil and gas companies have had access to debt and equity capital which they have invested in both acquisition and exploration activities. However, recently the access to external capital has become more restricted as a result of a deterioration in global credit liquidity and a slowing of economic growth which emerged in the latter half of 2007.

The third trend is the focus on Canada's oil sands deposits. In 2006 and 2007 the market for crude oil saw record high prices which persisted in the context of volatile geopolitical conditions. Strong demand growth and the forecast of continued growth from China, India and other developing nations also contributed to the quantum jump in crude oil prices. These strong prices brought into focus the relentless issue of reserve replacement and the continuing debate about the reliability of supply from established petroleum-producing regions. These rising oil prices and the need for dependable long-term supplies brought Canada's oil sands deposits into focus. The unofficial oil sands "press index" reached an all-time high, with financial papers reporting almost relentlessly on the projects under development and the potential importance to North American certainty of supply of the oil sands. As a result of the foregoing there was a significant increase in the prices being paid for oil sands properties in 2006 and 2007.

A fourth trend is the high level at which the industry is operating and the resulting intense competition for services and personnel to meet corporate capital expenditure programs. This has resulted in increased operating, exploration and development costs. See "Risk Factors".

## **BUSINESS OF THE CORPORATION**

Connacher is primarily engaged in the exploration for, and the development, production and refining of, crude oil and the exploration, development and production of natural gas. The Corporation's principal asset is a 100 percent working interest in approximately 98,000 acres of oil sands leases in the Divide and Halfway Creek regions near Fort McMurray, Alberta. The Corporation has commenced production from its first 10,000 bbl/d SAGD project (Pod One) at Great Divide and declared commerciality of the project effective March 1, 2008. The Algar Project, the Corporation's second 10,000 bbl/d SAGD project is presently before the regulators for approval. The Corporation also owns conventional producing crude oil and natural gas production and reserves at Battrum, Saskatchewan and at Marten Creek and Three Hills, Alberta, a 9,500 bbl/d refinery located in Great Falls, Montana and a 26 percent equity interest in Petrolifera, a public Canadian oil and natural gas company active in Argentina, Peru and Colombia.

## Principal Properties

The following paragraphs describe the Corporation's principal properties. Readers are cautioned that the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

### *Oil Sands*

#### *Great Divide and Halfway Creek, Alberta*

In this region of northeastern Alberta, the Corporation owns and operates 148.5 gross sections of oil sands leases (148.2 net sections or 94,848 net acres) and 21.25 gross sections (14 net sections or 8,960 net acres) of petroleum and natural gas rights. Several bitumen accumulations have been identified on these leases and further delineation and analysis is currently underway.

Once exploitable accumulations or pods have been identified, following a 3D seismic program and the drilling of core holes and with requisite results and the receipt of regulatory approvals, the Corporation anticipates using SAGD technology to extract bitumen from oil sands formations, located approximately 475 meters below surface.

Construction on Pod One commenced in November 2006 and was completed by August 2007. The total cost to complete Pod One was \$272 million, excluding capitalized interest, capitalized general and administrative costs and capitalized pre-operating costs. After commissioning, the Corporation commenced the sequential injection of steam into the 15 SAGD well pairs at Pod One in September 2007. In October 2007, the Corporation announced that it had delivered and sold to market its first truckload of dilbit from Pod One. The Corporation has determined that Pod One has achieved commerciality with an effective date of March 1, 2008. Accordingly, production, sales and related costs will be booked in the Corporation's income statement from that date forward. Full production of 10,000 bbl/d of bitumen is anticipated to be reached in the third quarter of 2008.

Additional pods have been delineated using core hole drilling and 3D seismic. In the second quarter of 2007, the Corporation submitted an application seeking regulatory approval for the Algar Project. The plant site for the proposed Algar Project is to be situated approximately eight kilometers east of Pod One. Upon receipt of all regulatory approvals, which are anticipated to be received in mid 2008, and following consultation with stakeholders, the Corporation will commence construction at the Algar Project. Advanced engineering, design and procurement activities have already been initiated. The cost to complete the Algar Project and to commence steaming is estimated to be approximately \$326 million, excluding capitalized interest, general and administrative and pre-operating costs. Costs for the Algar Project are anticipated to be higher than Pod One due to its further distance from Highway 63, the addition of waste treatment recycling capabilities that will also serve Pod One, an additional well pad required to optimize reservoir management and the prospective facilitation of future plant expansion to process incremental future production, as well as inflationary pressures on costs for labour, services and equipment. Further core hole drilling and 3D seismic analysis is planned to further delineate identified accumulations on Connacher's land. Drilling of 120 core holes is ongoing on the Corporation's Great Divide leases in the winter of 2008. The actual number of core holes drilled will be dependent on rig availability, weather and timing of spring breakup. This data will be integrated into the existing core hole and seismic database to determine which, if any, pods have sufficient size, areal extent and requisite reservoir quality to be confirmed as projects in addition to Pod One and the Algar Project.

As at December 31, 2007 the Connacher GLJ Report estimated the Corporation's Great Divide 1P reserves to be approximately 53 million barrels of bitumen, 2P reserves to be approximately 178 million barrels of bitumen and the 3P reserves to be approximately 242 million barrels of bitumen. In addition, on a best estimate basis, contingent resources were also assigned resulting in estimated 2P bitumen reserves and best estimate of contingent bitumen resources of approximately 303 million barrels. The Corporation's 3P bitumen reserves and high estimate of contingent and prospective bitumen resources were estimated at approximately 799 million barrels. There are different risks associated with reserves and resources and the specific categories of reserves and resources. See "Bitumen Resources - Consolidated Bitumen Resources and Total Reserves".

On February 25, 2008 the Corporation entered into a pooling arrangement totalling 38.5 gross sections of oil sands leases in the Halfway Creek area with Alberta Oilsands Inc. Under this arrangement, 15.5 sections were contributed by the Corporation. The pooling arrangement will result in the joint ownership, evaluation and potential development of any resources which may be identified on the subject leases. The agreement provides for the joint operatorship during the initial two years of the evaluation program, with Connacher the designated operator of any subsequent evaluation program(s) and of any identifiable development program(s) which may occur.

### ***Conventional Crude Oil and Natural Gas Assets***

Connacher's principal conventional operations are at Marten Creek and Three Hills in Alberta and at Battrum, Saskatchewan.

#### *Marten Creek, Alberta*

Marten Creek is a natural gas prone area located almost due west of Great Divide. Natural gas in the region is produced from various relatively shallow zones in the Cretaceous formation at a depth of approximately 2,000 feet. The Corporation operates 100 percent of its petroleum and natural gas leases. Daily gross natural gas production at Marten Creek for 2007 averaged 8.2 mmcf/d. The Corporation owns an 80 percent interest in approximately 138,400 gross acres (114,682 net acres). The Corporation has in excess of 2,000 kilometers of two-dimensional, or 2D, seismic data to explore and develop this area. Over 15 potential drilling locations have been identified on existing lands and the Corporation anticipates drilling 12 to 15 wells on its lands in this region in 2008. Additional drilling locations are being identified on the Corporation's land holdings. This is a winter work area and generally all work must be completed by the end of March in any given year. The Corporation also anticipates tying in 1,000 gross boe/d (6 mmcf/d) of tested natural gas production in the first quarter of 2008. These volumes were largely discovered and confirmed during the Corporation's 2007 winter drilling campaign. The Connacher GLJ Report estimated the Corporation's 2P reserves in this area to be 5.7 million boes, of which 4.0 million boes are 1P reserves.

#### *Three Hills, Alberta*

In March 2006, the Corporation acquired the Three Hills and Twining properties ("**Three Hills**") through the Luke Acquisition. At the time of the Luke Acquisition, the Three Hills properties were producing approximately 200 boe/d. As a result of drilling additional wells in 2006, these properties ended 2006 producing approximately 413 boe/d. In 2007, production was curtailed due to the need to refurbish the Three Hills facility which was completed in 2007. Production has since been restored to pre-curtailement levels in the first quarter of 2008. The Connacher GLJ Report estimated the Corporation's 1P reserves in this area to be 0.7 million boes and the Corporation's 2P reserves were estimated to be 1.0 million boes.

#### *Battrum, Saskatchewan*

The Corporation owns and operates working interests of 100 percent in unitized and non unitized lands in the Battrum region of southwestern Saskatchewan. The properties produce medium gravity crude oil. Most of these properties were acquired in two transactions in 2003, with additional minor transactions completed in 2005 and 2006. For the year ended December 31, 2007 the Corporation's average production from this area was 668 bbl/d of oil and production was approximately 690 bbl/d of oil at the end of 2007. There are presently 46 net producing oil and injection wells in this area, which comprises 26,558 gross acres and 26,544 net acres. At December 31, 2007 the Connacher GLJ Report estimates the Corporation's working interest share of 2P crude oil reserves in this area to be 2.4 million barrels of crude oil, of which 1.8 million barrels are 1P reserves.

### **The Refinery**

On March 31, 2006, the Corporation completed the MRC Acquisition. See "The Corporation - General Development of the Corporation".

The Refinery is a profitable, complex cracking/asphalt refinery located in Great Falls, Montana near the Canadian border. It processes approximately 9,500 bbl/d of crude oil and produces approximately 10,000 bbl/d of finished products. The Refinery has a Muse-Stancil complexity rating of 10.0, which indicates the ability of the

Refinery to produce a broad range of refined products. The Refinery refines primarily Canadian Bow River crude oil, a heavy crude that is similar to the dilbit being produced at Great Divide. The Refinery produces a full range of transportation fuels, including gasoline, diesel and jet fuel with residual material being converted to asphalt products. The Refinery captures a portion of the differential between heavy oil and WTI resulting in an effective physical hedge against heavy oil price differential swings.

Since the acquisition in March 2006, the Refinery has generated after tax cash flow in excess of the Corporation's purchase price. The Refinery's continued profitability will largely depend on the spread between market prices for refined petroleum products and the cost of heavy crude oil. The Refinery operated at 99.8 percent of capacity in 2007 and refinery margins were at record levels in first and second quarters of 2007. Consistent with the general trend in the refining sector, refinery margins weakened during the third and fourth quarters of 2007 due to the narrowing of heavy crude oil differentials and in elasticity of refined product prices as crude oil prices climbed to record levels and economic conditions deteriorated.

The Refinery is uniquely positioned because of its close proximity to the markets it serves and its ability to refine heavy Canadian crude with access to both local and regional markets via trucking and rail outlets that directly service the Refinery on-site. Access to crude oil is provided through the Front Range Pipeline which transports Bow River crude and other Canadian crude supplies.

In order to comply with requirements of the U.S. Environmental Protection Agency, the Corporation implemented a clean fuels project which will allow the plant to produce ultra-low sulfur diesel and gasoline by the end of 2008. Initial engineering has been completed on this internally-financed \$21 million project; contracts have been awarded and the project is on schedule. The Corporation is evaluating its opportunities to expand the throughput at the Refinery to maintain the hedge on price differentials between heavy crude oil and WTI as the Corporation's oil sands bitumen production grows from the development of additional pods.

### **Ownership of Petrolifera**

As of the date of this Annual Information Form Connacher owns an undiluted 26 percent equity interest in Petrolifera. Petrolifera is a publicly traded crude oil and natural gas exploration and production company active in Argentina, Colombia and Peru with its common shares listed for trading on the TSX under the symbol "PDP".

Petrolifera holds approximately 497,000 acres of exploratory and production rights in Argentina, and is currently producing crude oil, natural gas and natural gas liquids at the company's Puesto Morales fields in the Neuquén Basin, Argentina. Petrolifera also holds 1.2 million acres of exploratory rights in Colombia and owns 5.2 million acres under two licenses in Peru, where it is conducting seismic on its Ucayali Block 107 in preparation for anticipated drilling of wells in 2008 and 2009. As of the date hereof, Connacher owns 13.1 million common shares of Petrolifera and options to purchase 200,000 common shares of Petrolifera. Based on the closing trading price of Petrolifera on March 25, 2008 of \$9.30, Connacher's ownership of common shares of Petrolifera (excluding common shares issuable upon the exercise of options) represents a \$122.2 million investment. Petrolifera has forecasted capital expenditures of \$144 million to complete active seismic and drilling programs during 2008.

Pursuant to NI 51-101, the Corporation is required to state the Corporation's share of Petrolifera's oil and gas reserves, future net revenue and costs incurred during 2007 separately from its own corresponding reserves data and other oil and gas information. Notwithstanding the equity accounting of the Corporation's investment in Petrolifera, the Corporation has no right or entitlement to the reserves and future net revenue of Petrolifera as a shareholder thereof. Set out in Schedule C to this Annual Information Form is a summary of the Corporation's 26 percent interest in Petrolifera's oil and gas reserves and future net revenue as at December 31, 2007 as evaluated by GLJ in the Petrolifera GLJ Report and reported by Petrolifera in its Annual Information Form for the year ended December 31, 2007. The Petrolifera GLJ Report was prepared using assumptions and methodology guidelines outlined in the COGE Handbook and in accordance with NI 51-101. The pricing used in the forecast price evaluations is set forth in the notes to the tables. All of the reserves assigned to Petrolifera in the Petrolifera GLJ Report are located in the Puesto Morales Concession in Argentina. Readers are cautioned that as a result of the exercise of any outstanding options of Petrolifera and the issuance by Petrolifera of additional securities, the Corporation's interest in Petrolifera's reserves will decrease, unless the Corporation participates in such issuances of securities.

The attached Schedule C has been prepared based on the publicly disclosed information that is contained in the Petrolifera AIF. For additional information beyond what is set forth in Schedule C reference should be made to the Petrolifera AIF which is posted on SEDAR ([www.sedar.com](http://www.sedar.com)) and is not incorporated by reference in this Annual Information Form.

## OIL AND NATURAL GAS RESERVES AND RESOURCES

Connacher engaged GLJ to prepare a report relating to the Corporation's reserves and resources as at December 31, 2007. The information set forth below relating to the Corporation's reserves and resources constitute forward looking information which is subject to certain risks and uncertainties. See "Forward Looking Information" and "Risk Factors".

### Oil, Natural Gas and Bitumen Reserves

Connacher's conventional crude oil and natural gas reserves are primarily located in three areas, the Battum area of Saskatchewan and the Marten Creek and Three Hills areas of Alberta. Connacher's bitumen reserves are located in the Great Divide region. Bitumen reserves have been assigned to Pod One, in the 1P, 2P and 3P categories and the Algar Project in the 2P and 3P categories. The Connacher GLJ Report assumed 47 SAGD well pairs for the proved case, 123 SAGD well pairs for the 2P case and 172 SAGD well pairs for the 3P case, with cumulative SORs of 2.7, 2.7 and 2.6 in each case, but declining to 2.4 during peak production periods. The cutoffs used by GLJ for probable reserves were 15 metres of net pay for proved reserves, 13 metres of net pay for 2P reserves and 10 metres of net pay for 3P reserves.

Set out below is a summary of the crude oil, natural gas and bitumen reserves and the value of future net revenue of the Corporation as at December 31, 2007 as evaluated by GLJ in the Connacher GLJ Report. The preparation date of the Connacher GLJ Report is February 28, 2008. The pricing used in the forecast price evaluations is set forth in the notes to the tables.

**Possible reserves were only evaluated with respect to the Corporation's bitumen reserves. The Corporation's conventional crude oil and natural gas reserves were not evaluated in the possible reserves category.**

Under NI 51-101, 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. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

**All evaluations of future revenue are after the deduction of royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenues contained in the following tables do not necessarily represent the fair market value of the Corporation's reserves. There is no assurance that the forecast price and cost assumptions contained in the Connacher GLJ Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the Connacher GLJ Report. The recovery and reserves estimates of the Corporation's properties described herein are estimates only. The actual reserves on the Corporation's properties may be greater or less than those calculated.**

**CONVENTIONAL AND NON-CONVENTIONAL RESERVES  
BASED ON FORECAST PRICES AND COSTS<sup>(8)</sup>**

	Light/Medium Crude Oil		Natural Gas		Bitumen	
	Gross <sup>(1)</sup>	Net <sup>(1)</sup>	Gross <sup>(1)</sup>	Net <sup>(1)</sup>	Gross <sup>(1)</sup>	Net <sup>(1)</sup>
	(m bbl)	(m bbl)	(mmcf)	(mmcf)	(m bbl)	(m bbl)
Proved Developed Producing <sup>(2)(5)</sup>	1,512	1,257	17,204	14,120	15,025	14,847
Proved Developed Non-Producing <sup>(2)(6)</sup>	630	491	8,605	6,858	-	-
Proved Undeveloped <sup>(2)(7)</sup>	213	160	1,098	835	37,991	33,355
Total Proved <sup>(2)</sup>	2,356	1,908	26,908	21,813	53,016	48,202
Total Probable <sup>(3)</sup>	694	565	11,533	9,453	124,776	108,044
Total Proved Plus Probable <sup>(2)(3)</sup>	3,050	2,473	38,441	31,265	177,792	156,246
Total Possible <sup>(4)</sup>	-	-	-	-	64,217	54,791
Total Proved Plus Probable Plus Possible <sup>(2)(3)(4)</sup>	3,050	2,473	38,441	31,265	242,009	211,037

**NET PRESENT VALUE OF FUTURE NET REVENUE  
BASED ON FORECAST PRICES AND COSTS<sup>(8)</sup>**

(M\$)	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes Discounted At					Net Unit Value Before Income Tax Discounted at 10%/year	
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%	(\$/boe)	(\$/Mcfe)
	Proved Developed Producing <sup>(2)(5)</sup>	500,024	415,194	352,902	305,638	268,843	481,414	401,085	342,025	297,128	262,093	19.12
Proved Developed Non-Producing <sup>(2)(4)(6)</sup>	47,912	35,581	28,053	23,021	19,430	40,005	29,214	22,847	18,707	15,812	17.16	2.86
Proved Undeveloped <sup>(2)(7)</sup>	658,263	373,605	222,265	137,231	86,955	503,195	278,832	160,614	94,861	56,423	6.60	1.10
Total Proved <sup>(2)</sup>	1,206,199	824,380	603,219	465,891	375,228	1,024,614	709,131	525,486	410,697	334,329	11.22	1.87
Total Probable <sup>(3)</sup>	2,752,267	1,208,299	590,586	310,074	166,795	2,057,943	885,855	418,462	206,491	98,204	5.36	0.89
Total Proved Plus Probable <sup>(2)(3)</sup>	3,958,466	2,032,679	1,193,805	775,965	542,023	3,082,556	1,594,986	943,948	617,188	432,533	7.28	1.21
Total Possible <sup>(4)</sup>	1,964,238	439,521	114,286	39,678	21,493	1,468,027	325,215	84,364	30,006	17,044	1.78	0.30
Total Proved Plus Probable Plus Possible <sup>(2)(3)(4)</sup>	5,922,704	2,472,200	1,308,091	815,643	563,516	4,550,583	1,920,201	1,028,312	647,194	449,577	5.20	0.87

**FUTURE NET REVENUE  
(UNDISCOUNTED)  
BASED ON FORECAST PRICES AND COSTS<sup>(8)</sup>**

	Revenue <sup>(9)</sup> (M\$)	Royalties <sup>(10)</sup> (M\$)	Operating Expenses (M\$)	Capital Costs (M\$)	Abandonment Costs (M\$)	Future Net Revenue Before Income Taxes (M\$)	Income Taxes (M\$)	Future Net Revenue After Income Taxes (M\$)
Total Proved <sup>(2)</sup>	2,741,826	294,235	919,312	309,561	12,520	1,206,199	181,585	1,024,614
Total Proved Plus Probable <sup>(2)(3)</sup>	9,381,084	1,210,532	3,069,161	1,117,818	25,107	3,958,466	875,910	3,082,556
Total Proved Plus Probable Plus Possible <sup>(2)(3)(4)</sup>	13,892,000	1,862,000	4,477,000	1,589,000	36,000	5,923,000	1,372,000	4,551,000

**FUTURE NET REVENUE BY PRODUCTION GROUP  
BASED ON FORECAST PRICES AND COSTS<sup>(8)</sup>**

	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year)	Net Unit Value	
		(M\$)	(\$/boe)	(\$/Mcfe)
Total Proved <sup>(2)</sup>	Light and medium crude oil (including solution gas and by- products)	50,395	25.13	4.19
	Associated gas and non-associated gas (including natural gas liquids and excluding solution gas)	61,104	17.27	2.88
	Bitumen	491,720	10.20	1.70
Total Proved Plus Probable <sup>(2)(3)</sup>	Light and medium crude oil (including solution gas and by- products)	62,244	23.92	3.99
	Associated gas and non-associated gas (including natural gas liquids and excluding solution gas)	80,956	15.93	2.66
	Bitumen	1,050,604	6.72	1.12
Total Proved Plus Probable Plus Possible <sup>(2)(3)(4)</sup>	Light and medium crude oil (including solution gas and by- products)	62,244	23.92	3.99
	Associated gas and non-associated gas (including natural gas liquids and excluding solution gas)	80,956	15.93	2.66
	Bitumen	1,164,890	5.52	0.92

**RECONCILIATION OF COMPANY CONVENTIONAL AND NON-CONVENTIONAL RESERVES BY  
PRINCIPAL PRODUCT TYPE BASED ON FORECAST PRICES AND COSTS<sup>(8)</sup>**

The following table sets forth a reconciliation of the changes in Connacher's working interest, before royalties, of light crude oil, associated and non-associated natural gas (combined) and bitumen reserves as at December 31, 2007 against such reserves as at December 31, 2006 based on the forecast price and cost assumptions set forth in Note 8.

	Light and Medium Oil			Associated and Non-Associated Natural Gas			Bitumen		
	Gross Proved <sup>(1)(2)</sup>	Gross Probable <sup>(1)(3)</sup>	Gross Proved Plus Probable <sup>(1)(2)(3)</sup>	Gross Proved <sup>(1)(2)</sup>	Gross Probable <sup>(1)(3)</sup>	Gross Proved Plus Probable <sup>(1)(2)(3)</sup>	Gross Proved <sup>(1)(2)</sup>	Gross Probable <sup>(1)(3)</sup>	Gross Proved Plus Probable <sup>(1)(2)(3)</sup>
	(mdbl)	(mdbl)	(mdbl)	(mmcf)	(mmcf)	(mmcf)	(mdbl)	(mdbl)	(mdbl)
At December 31, 2006	2,421	786	3,207	24,691	8,769	33,460	43,841	40,307	84,148
Extensions and Improved Recovery	280	(51)	230	6,005	4,739	10,745	9,200	12,008	21,207
Technical Revisions	(86)	(47)	(132)	(93)	(1,942)	(2,035)	-	-	-
Discoveries	-	-	-	-	-	-	-	72,462	72,462
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	24	6	30	(310)	(34)	(344)	-	-	-
Production	(285)	-	(285)	(3,384)	-	(3,384)	(25)	-	(25)
At December 31, 2007	2,356	694	3,050	26,908	11,533	38,441	53,016	124,776	177,792

**Notes:**

- (1) "Gross Reserves" are the Corporation's working interest (operating or non-operating) share before deducting royalties and without including any royalty interests of the Corporation. "Net Reserves" are the Corporation's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interests in reserves.
- (2) "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.
- (3) "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) "Possible" reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.
- (5) "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 certainty.
- (6) "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.
- (7) "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 category (proved, probable, possible) to which they are assigned.
- (8) The pricing assumptions used in the Connacher GLJ Report with respect to values of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

	<b>Light and Medium Crude Oil</b>	<b>Bitumen Wellhead Current</b>	<b>Natural Gas</b>	<b>Inflation</b>	<b>Bank of Canada Average Noon Exchange Rate</b>
	<b>WTI Cushing Oklahoma (\$US/bbl)</b>	<b>(\$Cdn/bbl)</b>	<b>Alberta Spot (\$Cdn/mcf)</b>	<b>%/year</b>	<b>\$US/\$Cdn</b>
Forecast					
2008	92.00	43.22	6.75	2.0	1.000
2009	88.00	41.85	7.55	2.0	1.000
2010	84.00	40.47	7.60	2.0	1.000
2011	82.00	40.28	7.60	2.0	1.000
2012	82.00	40.28	7.60	2.0	1.000
2013	82.00	41.37	7.60	2.0	1.000
2014	82.00	42.45	7.80	2.0	1.000
2015	82.00	43.53	7.97	2.0	1.000
2016	82.02	44.62	8.14	2.0	1.000
2017	83.66	45.68	8.48	2.0	1.000
Thereafter	+2.0%/yr	+2.0%/yr	+2%	2.0	1.000

(9) Values include processing and other income.

(10) Values include Alberta Royalty Tax Credit.

Weighted average historical prices realized by the Corporation for the year ended December 31, 2007 were \$52.80/bbl for light and medium crude and \$6.38 /mcf for natural gas. Sales of bitumen during the fourth quarter of 2007 were capitalized pending a determination of commerciality.

***Undeveloped Reserves***

Proved undeveloped reserves are generally those reserves related to planned infill drilling locations. Such reserves may also relate to wells that have been drilled and not yet tied in because of seasonal access issues, the need for further testing of the wells or construction of pipelines and production facilities for the well.

At December 31, 2007, Connacher's conventional net proved undeveloped reserves of 213 mbbbls of crude oil were located at Batrum, Saskatchewan and proved undeveloped reserves of 1,098 mmcf of natural gas were located at Marten Creek, Alberta. At Great Divide, proved undeveloped reserves of 37,991 mbbbls of bitumen were assigned by GLJ in the Connacher GLJ Report. All of the Corporation's conventional and 20 percent of the Corporation's proved unconventional undeveloped reserves are scheduled to be developed within the next two years. The balance will be developed as oil sands plant capacity becomes available.

The following table sets out the volumes of proved undeveloped reserves that were attributed for each of the Corporation's product types for each of the Corporation's most recent three financial years and in the aggregate before that time using forecast prices and costs:

Period	Light and Medium Crude Oil (mdbl)	Natural Gas (mmcf)	Bitumen (mdbl)
Aggregate Prior to December 31, 2005	-	-	-
December 31, 2005	-	-	-
December 31, 2006	213	-	37,991
December 31, 2007	-	1,098	-

The Connacher GLJ Report estimates the Corporation's probable reserves to be 694 mdbl of light or medium oil, 11,535 mmcf of natural gas and 124,776 mdbl of bitumen. Probable undeveloped reserves relate to wells to be drilled, tied in and brought on-stream in the future. Approximately 20 percent of the Corporation's proved plus probable undeveloped conventional reserves will be developed over the next five years. A significant portion of the Corporation's probable unconventional undeveloped reserves will be developed primarily with the approval, construction, startup and commissioning of the Algar SAGD project which is scheduled for startup in 2009, subject to regulatory approval.

The following table sets out the volumes of probable undeveloped reserves that were attributed for each of the Corporation's product types for each of the Corporation's most recent three financial years and in the aggregate before that time using forecast prices and costs:

Period	Light and Medium Crude Oil (mdbl)	Natural Gas (mmcf)	Bitumen (mdbl)
Aggregate Prior to December 31, 2005	-	-	-
December 31, 2005	-	-	40,306
December 31, 2006	68	-	-
December 31, 2007	-	1,830	76,652

### ***Significant Factors or Uncertainties***

The Corporation does not anticipate that any important economic factors or significant uncertainties would affect particular components of the reserves data. Notwithstanding a number of factors which are beyond the Corporation's control can significantly affect the reserves, including product pricing, royalty and tax regimes, changing operating and capital costs, surface access issues, availability of services and processing facilities and technical issues affecting well performance. See "Risk Factors".

### ***Future Development Costs***

The following table sets forth the development costs deducted in the estimation of future net revenue attributable to each of the following reserves categories contained in the Connacher GLJ Report:

	Total Proved Future Development Costs Using Forecast Dollar Costs (M\$)	Total Proved Plus Probable Future Development Costs Using Forecast Dollar Costs (M\$)	Total Proved Plus Probable Plus Possible Future Development Costs Using Forecast Dollar Costs (M\$)
2008	40,838	208,438	219,000
2009	28,815	146,676	130,000
2010	31	31	-
2011	1,284	29,841	2,000
2012	18,266	24,652	47,000
Total for all remaining years	220,327	708,180	1,191,000
Total, undiscounted	309,561	1,117,818	1,589,000

Future development costs are expected to be funded from a combination of the following: operational cash flow, proceeds from the offering of the Notes, debt and equity financing and/or farmout arrangements with other companies. The timing of such funding may influence the timing of the developmental work expenditures.

### ***Crude Oil and Gas Properties and Wells***

The following table sets forth the number of crude oil and natural gas wells in which Connacher held a working interest as at December 31, 2007:

	<b>Crude Oil</b>		<b>Natural Gas</b>	
	<b>Gross<sup>(1)</sup></b>	<b>Net<sup>(1)</sup></b>	<b>Gross<sup>(1)</sup></b>	<b>Net<sup>(1)</sup></b>
Alberta				
Producing	13	12	72	65
Non-producing	8	7	34	31
Saskatchewan				
Producing	46	46	-	-
Non-producing	34	34	11	10
<b>Total<sup>(2)</sup></b>	<b>101</b>	<b>99</b>	<b>117</b>	<b>106</b>

**Notes:**

- (1) "Gross Wells" are the total number of wells in which Connacher has an interest. "Net Wells" are the number of wells obtained by aggregating Connacher's working interest in each of its gross wells.
- (2) Does not include 15 gross and net bitumen SAGD well pairs.

### ***Costs Incurred***

The following table summarizes the capital expenditures made by Connacher on crude oil, bitumen and natural gas properties for the year ended December 31, 2007.

<b>Property Acquisition Costs</b>		<b>Exploration Costs</b>	<b>Development Costs</b>
<b>(M\$)</b>		<b>(M\$)</b>	<b>(M\$)</b>
<b>Proved Properties</b>	<b>Unproved Properties</b>		
-	4,916	39,332	247,027

### ***Exploration and Development Activities***

The following table sets forth the number of exploratory and development wells which Connacher completed during its 2007 financial year:

	<b>Exploratory Wells</b>		<b>Development Wells</b>	
	<b>Gross<sup>(1)</sup></b>	<b>Net<sup>(1)</sup></b>	<b>Gross<sup>(1)</sup></b>	<b>Net<sup>(1)</sup></b>
Oil Wells <sup>(2)</sup>	75	75	2	2
Gas Wells	3	3	5	5
SAGD Well Pairs	-	-	15	15
Suspended Wells	2	2	2	2
Dry Holes	8	7	-	-
<b>Total Completed Wells</b>	<b>88</b>	<b>87</b>	<b>24</b>	<b>24</b>

**Notes:**

- (1) "Gross Wells" are the total number of wells in which Connacher has an interest. "Net Wells" are the number of wells obtained by aggregating Connacher's working interest in each of its gross wells.
- (2) Includes 75 oil sands exploration delineation core holes.

In 2008 focus will continue to be on Great Divide, increasing anticipated production at Pod One to 10,000 bbl/d and commencement of construction on the Algar Project upon receipt of regulatory approval. Other significant work will also be carried out on the Corporation's conventional acreage and at the Refinery. A firm and contingent cash capital budget approaching \$373 million is envisaged for 2008, including \$29 million of contingent expenditures related to the possible Refinery expansion and pipeline pre-engineering at Great Divide, with approximately \$216 million directed to the development of the Algar Project and approximately \$50 million for the continued evaluation of additional pods and undeveloped acreage in the Great Divide region. Approximately \$40 million is targeted for expenditure on conventional activity, including drilling for natural gas at Marten Creek and other selected regions in northern Alberta, oil development drilling at Three Hills, Alberta and ongoing projects at Battrum, Saskatchewan. It is also anticipated \$33 million will be invested in the operation of the Refinery during

2008, primarily to complete a new hydrogen plant which will allow for the production of ultra-low sulphur diesel and to increase product storage and improve refined product off-loading capabilities.

***Properties with No Attributed Reserves***

The following table sets out the Corporation's undeveloped land position effective December 31, 2007.

	<b>Undeveloped Acreage (Acres)</b>	
	<b>Gross<sup>(1)</sup></b>	<b>Net<sup>(1)</sup></b>
Alberta		
Conventional	164,969	135,144
Oil Sands	94,080	93,888
Saskatchewan	65,015	53,632
British Columbia	3,948	3,552
<b>Total</b>	<b>328,012</b>	<b>286,216</b>

**Note:**

(1) "Gross" means the total area of properties in which the Corporation has a working interest. "Net" means the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

The Corporation does not expect its rights to explore, develop and exploit any of its unproved property to expire within the next year.

The Corporation engaged Sayer to prepare an independent evaluation of the undeveloped land acreage of the Corporation as at December 31, 2007. In the Sayer Report a fair value of approximately \$14.7 million or approximately \$62.81 per gross acre was assigned to Connacher's non-reserve oil and gas properties, excluding its oil sands acreage. In determining the market value, Sayer based their evaluation on the following factors:

1. The acquisition cost, provided that there have been no material changes in the unproved property, the surrounding properties, or the general oil and gas climate since the acquisition;
2. Recent sales by others of interests in the same unproved property;
3. Terms and conditions, expressed in monetary terms, of recent farm-in agreements related to the unproved properties;
4. Terms and conditions, expressed in monetary terms, of recent work commitments related to the unproved property; and
5. Recent sales of similar properties in the same general area.

***Asset Retirement Obligations***

The Corporation follows the Canadian Institute of Chartered Accountants' standard on Asset Retirement Obligations. This standard requires liability recognition for retirement obligations associated with long-lived assets, which would include abandonment of oil and natural gas wells, related facilities, compressors and gas plants, removal of equipment from leased acreage and returning such land to its original condition. Under the standard, the estimated fair value of each asset retirement obligation is recorded in the period a well or related asset is drilled, constructed or acquired. Fair value is estimated using the present value of the estimated future cash outflows to abandon the asset at the Corporation's credit-adjusted risk-free interest rate. The obligation is reviewed regularly by Management based upon current regulations, costs, technologies and industry standards. The discounted obligation is recognized as a liability and is accreted against income until it is settled or the property is sold and is included as a component of depletion and depreciation expense. Actual restoration expenditures are charged to the accumulated obligation as incurred.

As at December 31, 2007, the estimated total undiscounted amount required to settle the asset retirement obligations in respect of the Corporation's 301 net producing and non-producing wells and facilities, net of estimated salvage recoveries, was \$60 million. These obligations will be settled over the useful lives of the underlying assets, which currently extend up to 25 years. The 10 percent discounted present value of this amount is \$22 million. Over the next three years, the Corporation expects to incur \$900,000 (equivalent to \$750,000 discounted at 10 percent) of these expenditures. No asset retirement obligations were booked for the Refinery as the Corporation expects to maintain and operate the Refinery indefinitely.

In the Connacher GLJ Report, well abandonment costs for total proved plus probable plus possible reserves were estimated to be \$36 million, undiscounted, and \$5 million, discounted at 10 percent. These estimates are in respect of well costs only and do not include costs to abandon pipelines and facilities, which the Corporation has included in determining its asset retirement obligation. These costs include abandonment of 273 net wells. Of the undiscounted future net revenue estimated by GLJ, \$26.6 million of abandonment and reclamation costs relating to facilities have not been deducted.

### ***Tax Horizon***

Income earned in Canada is not expected to attract taxes until the Corporation utilizes its accumulated tax pools and loss carry forwards, which exceed \$500 million. Based on anticipated capital spending, which augments the tax pools, the Corporation does not expect to pay Canadian income taxes until approximately 2010. The Corporation's US refining subsidiary is currently cash taxable.

### ***Production Estimates***

The following table sets forth the volume of working interest production, before royalties, estimated for 2008 in the Connacher GLJ Report under the combined 2P reserves model:

<b>Light/Medium Crude Oil (mbbl)</b>	<b>Natural Gas (mmcf)</b>	<b>Natural Gas Liquids (mbbl)</b>	<b>Bitumen (mbbl)</b>
379	4,911	-	2,976

The following table indicates the volume of working interest production, before royalties, estimated for 2008 from fields considered to be individually important:

	<b>Light/Medium Crude Oil (mbbl)</b>	<b>Natural Gas (mmcf)</b>	<b>Natural Gas Liquids (mbbl)</b>	<b>Bitumen (mbbl)</b>
Battrum, Saskatchewan	233	-	-	-
Marten Creek, Alberta	-	4,038	-	-
Great Divide, Alberta	-	-	-	2,976

### ***Production History***

The following table sets forth certain information in respect of production, product prices received, royalties, production costs and netbacks received by the Corporation for each quarter of its most recently completed financial year:

	<b>Three Months Ended March 31, 2007</b>	<b>Three Months Ended June 30, 2007</b>	<b>Three Months Ended September 30, 2007</b>	<b>Three Months Ended December 31, 2007</b>
Average Daily Production				
Light and Medium Oil (bbl/d)	905	731	781	752
Natural Gas (mcf/d)	9,665	9,017	9,413	8,889
Average Net Prices Received				
Light and Medium Oil (\$/bbl)	49.09	49.79	55.98	56.79
Natural Gas (\$/mcf)	7.76	7.02	4.70	5.82
Royalties				
Light and Medium Oil (\$/bbl)	11.53	12.45	12.80	8.51

	<u>Three Months Ended March 31, 2007</u>	<u>Three Months Ended June 30, 2007</u>	<u>Three Months Ended September 30, 2007</u>	<u>Three Months Ended December 31, 2007</u>
Natural Gas (\$/mcf)	1.84	(0.21)	0.52	0.87
Production Costs				
Light and Medium Oil (\$/bbl)	10.76	12.15	13.46	18.48
Natural Gas (\$/mcf)	1.21	2.26	1.13	1.90
Netback Received				
Light and Medium Oil (\$/bbl)	26.80	25.19	29.72	29.80
Natural Gas (\$/mcf)	4.71	4.97	3.05	3.05

The following table indicates the Corporation's average daily production for the year ended December 31, 2007 from fields considered to be individually important:

	<u>Light/Medium Crude Oil (bbl/d)</u>	<u>Natural Gas (mcf/d)</u>	<u>Natural Gas Liquids (bbl/d)</u>
Battrum, Saskatchewan	668	-	-
Marten Creek, Alberta	-	8,182	-

### ***Competitive Conditions***

The petroleum and natural gas industry is competitive in all aspects. Connacher competes with numerous other companies for access to capital to fund its exploration and development activities. It also competes with other companies in the search for exploration and development prospects and in the marketing of its production.

Connacher attempts to enhance its competitive position by:

- focusing on a limited number of core areas;
- maintaining high working interests;
- wherever possible, operating properties;
- securing control over infrastructure such as pipelines and gas processing facilities;
- employing highly competent professional staff who use leading-edge technology; and
- striving to be a low-cost producer.

### **Bitumen Resources**

Currently, in the Great Divide region, proved, probable and possible reserves have been assigned to Pod One, which has received regulatory approval and has commenced production. Probable and possible reserves have been assigned to the Algar Project, for which regulatory application has been made for development.

The Connacher GLJ Report also provided estimates of Contingent Resources associated with identified pods that are outside current areas of application. Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. There is no certainty that it will be commercially viable to produce any portion of the resources. Contingent Resources were assigned in regions with lower core-hole drilling density than the reserve regions and are outside current areas of application for development. These resource estimates are not classified as reserves at this time, pending further reservoir delineation, project application, facility and reservoir design work. Contingent Resources entail additional commercial risk than reserves, which have not been included in the net present valuation.

A range of Contingent Resource estimates (Low, Best and High) were prepared to reflect a range of technical uncertainty. Low Estimate Contingent Resources were assigned to mapped regions of oil-in-place with at least 15 meters of continuous bitumen pay along with a conservative estimate of recovery factor. The Low Estimate was also restricted to the Algar Project, which is awaiting regulatory approval. Best Estimate Contingent Resources were assigned to mapped regions of oil-in-place of identified pods outside areas of application for development with at least 13 meters of continuous bitumen pay along with a best estimate of recovery factor. High Estimate Contingent Resources were assigned to mapped regions of oil-in-place of identified pods outside areas of application

for development with at least 10 meters of continuous bitumen pay along with a more optimistic estimate of recovery factor.

The Connacher GLJ Report also provided estimates of Prospective Resources attributable to undiscovered pods. Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. There is no certainty that any portion of the Prospective Resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the Prospective Resources. Prospective Resources were attributable to undiscovered pods in unexplored regions, utilizing average parameters from the pods discovered to date and the statistical success within the explored regions of the leases. Prospective Resources entail additional commercial risk than reserves and Contingent Resources, which have not been included in the net present valuation.

A range of Prospective Resources estimates were prepared to reflect a range of technical uncertainty. No Low Estimate Prospective resources were assigned, given the risk of not encountering an undiscovered pod of sufficient size to be considered commercial.

### BITUMEN RESOURCES

The following table sets out Low, Best and High estimates of the Corporation's Contingent and Prospective bitumen resources:

Marketable Reserves, Resources	Total Company Interest (mdbl)	Contingent Resources		Prospective Resources	
		Total Company Interest (mdbl)	Net After Royalty (mdbl)	Total Company Interest (mdbl)	Net After Royalty (mdbl)
Low Estimate	61,325		56,008	-	-
Best Estimate	125,531		110,342	113,398	98,728
High Estimate	209,885		183,962	347,133	303,291

### CONSOLIDATED BITUMEN RESOURCES AND TOTAL RESERVES

The following table sets out information pertaining to the Corporation's consolidated total reserves and bitumen resources:

Marketable Reserves, Resources	Gross Interest			Net After Royalty			Future Net Revenue		
	Bitumen (mdbl)	Light/Medium Crude Oil (mdbl)	Natural Gas (mmcf)	Bitumen (mdbl)	Light/Medium Crude Oil (mdbl)	Natural Gas (mmcf)	Before Tax Present Value at 0%	Before Tax Present Value at 5%	Before Tax Present Value at 10%
							M\$	M\$	M\$
1P Reserves	53,016	2,356	26,908	48,202	1,908	21,813	1,206,199	824,380	603,219
2P Reserves	177,792	3,050	38,441	156,246	2,473	31,265	3,958,466	2,032,679	1,193,805
3P Reserves	242,009	3,050	38,441	211,037	2,473	31,265	5,922,704	2,472,200	1,308,091
Low Estimate Contingent Resources	61,325	-	-	56,008	-	-	839,137	376,364	141,916
Best Estimate Contingent Resources	125,531	-	-	110,342	-	-	2,762,296	897,320	348,108
High Estimate Contingent Resources	209,885	-	-	183,962	-	-	4,354,089	1,691,998	741,600
1P Reserves and Low Estimate Contingent Resources	114,340	2,356	26,908	104,210	1,908	21,813	2,045,336	1,200,744	745,135
2P Reserves and Best Estimate Contingent Resources	303,323	3,050	38,441	266,588	2,473	31,265	6,720,762	2,929,999	1,541,912
3P Reserves and High Estimate Contingent Resources	451,895	3,050	38,441	394,999	2,473	31,265	10,276,793	4,164,198	2,049,690
Low Estimate Prospective Resources	-	-	-	-	-	-	-	-	-
Best Estimate Prospective Resources	113,398	-	-	98,728	-	-	2,548,164	918,522	379,308
High Estimate Prospective Resources	347,133	-	-	303,291	-	-	8,795,528	2,272,717	724,342

Marketable Reserves, Resources	Gross Interest			Net After Royalty			Future Net Revenue		
	Bitumen (mbbl)	Light/Medium Crude Oil (mbbl)	Natural Gas (mmcf)	Bitumen (mbbl)	Light/Medium Crude Oil (mbbl)	Natural Gas (mmcf)	Before Tax Present Value at 0% M\$	Before Tax Present Value at 5% M\$	Before Tax Present Value at 10% M\$
1P Reserves and Low Estimate Contingent and Prospective Resources	114,340	2,356	26,908	104,210	1,908	21,813	2,045,335	1,200,744	745,135
2P Reserves and Best Estimate Contingent and Prospective Resources	416,720	3,050	38,441	365,316	2,473	31,265	9,268,926	3,848,521	1,921,220
3P Reserves and High Estimate Contingent and Prospective Resources	799,028	3,050	38,441	698,291	2,473	31,265	19,072,321	6,436,915	2,774,033

The estimated future net revenues contained in the foregoing tables do not necessarily represent the fair market value of the Corporation's reserves and resources. Additional information with respect to the Corporation's 1P, 2P and 3P reserves can be found under the heading "Oil and Natural Gas Reserves and Resources - Oil, Natural Gas and Bitumen Reserves" in this Annual Information Form.

### DIRECTORS AND OFFICERS

As of the date of this Annual Information Form the name, municipality of residence, positions held with the Corporation and principal occupation during the preceding five years of each of the directors and officers of the Corporation are as follows:

Name and Municipality of Residence	Positions Held	Principal Occupation During the Preceding Five Years	Director Since
Richard A. Gusella Calgary, Alberta Canada	President, Chief Executive Officer and Director	President and Chief Executive Officer of Connacher since May 2001 and Petrolifera from November 2004 to March 2005. Executive Chairman of Petrolifera since March 2005.	May 30, 2001
Charles W. Berard <sup>(3)(5)</sup> Calgary, Alberta Canada	Director	Partner, Macleod Dixon LLP, a law firm.	May 30, 2001
D. Hugh Bessell <sup>(1)(2)(3)(4)</sup> Toronto, Ontario Canada	Director	Independent Businessman. Prior thereto, Deputy Chairman and Chief Operating Officer of KPMG LLP.	December 1, 2005
Colin M. Evans <sup>(1)(2)(4)(5)</sup> Calgary, Alberta Canada	Director	Vice President, Finance, Milestone Exploration Inc., a private oil and natural gas exploration and production company. President of Evans & Co. Inc., a private consulting corporation providing financial and operating advisory services to oil and gas corporations from 1994 to 2004.	April 5, 2004
Stewart D. McGregor <sup>(2)(3)(7)</sup> Calgary, Alberta Canada	Director	President of Camun Consulting Corporation, a private investment holding company, since 1994.	June 12, 2003
W.C. (Mike) Seth <sup>(1)(4)(5)</sup> Calgary, Alberta Canada	Director	President, Seth Consultants Ltd. a private consulting firm. Prior thereto Chairman of McDaniel & Associates Consultants Ltd. and prior thereto, President and Managing Director of McDaniel & Associates Consultants Ltd.	December 9, 2005

<b>Name and Municipality of Residence</b>	<b>Positions Held</b>	<b>Principal Occupation During the Preceding Five Years</b>	<b>Director Since</b>
Richard R. Kines Calgary, Alberta Canada	Vice President, Finance and Chief Financial Officer	Vice President, Finance and Chief Financial Officer since December 2004 and Chief Financial Officer of Connacher since June 2003. Prior thereto, financial consultant of Connacher since April 2002.	-
Peter D. Sametz Calgary, Alberta Canada	Executive Vice President and Chief Operating Officer	Executive Vice President and Chief Operating Officer of Connacher since December 2004. From February 2004, Vice President Operations of Connacher. Prior thereto, simultaneously Chief Operating Officer and a director of Surge Petroleum Inc., a public oil company listed on the TSX Venture Exchange since July 2000 and a Principal of Inline Petroleum Management Incorporated from 1997 to February 2004.	-
Stephen A. Marston Calgary, Alberta Canada	Vice President, Exploration	Vice President, Exploration of Connacher since January 2006. Prior thereto, Chief Geophysicist of Real Resources Inc. since January 2001.	-
Cameron M. Todd Calgary, Alberta Canada	Vice President, Refining and Marketing	Vice President, Refining and Marketing of Connacher since May 2006. Prior thereto, Vice President, Worldwide Marketing of Pioneer Natural Resources from June 2002 to May 2006.	-
Russell W. Longley Calgary, Alberta Canada	Vice President, Operations	Vice President, Operations of Connacher since May 2007. Prior thereto, was instrumental in the start-up, growth and divestment of a private junior exploration gas company.	-
Stephen J. De Maio Calgary, Alberta Canada	Vice President, Project Development	Vice President, Project Development of Connacher since November 2006 and Consultant Engineer of Connacher from March 2006 to November 2006. Prior thereto, Consultant Engineer of Total E&P Canada from August 2005 to August 2006 and of Deer Creek Energy Limited from March 2005 to August 2005. Chief Executive Officer of Efficient Energy Ltd. from December 2000 to March 2005.	-
Grant D. Ukrainetz Calgary, Alberta Canada	Vice President, Corporate Development	Vice President, Corporate Development of Connacher since December 2007 and Treasurer of Connacher from June 2006 to February 2008. Prior thereto, Supervisor, Treasury and Treasury and Risk Management Analyst of Talisman Energy Inc. since September 2001.	-
I. Scott Carrothers Calgary, Alberta Canada	Treasurer	Treasurer of Connacher since February 2008. Prior thereto, Manager Corporate Finance with Paramount Resources Ltd. since 2004 and prior thereto, Senior Treasury Advisor and Corporate Finance Advisor with Encana Corporation and Alberta Energy Company Ltd. since 1999.	-
Jennifer K. Kennedy Calgary, Alberta Canada	Secretary	Partner, Macleod Dixon LLP, a law firm, since January 2000.	-

**Notes:**

- (1) Member of the Audit Committee.
- (2) Member of the Human Resources Committee.
- (3) Member of the Governance Committee.
- (4) Member of the Reserves Committee.
- (5) Member of the Health, Safety and Environment Committee.
- (6) Connacher does not have an Executive Committee.
- (7) Lead Director.

As at March 25, 2007, the directors and executive officers of Connacher, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 3,136,856 Common Shares constituting approximately 1.5 percent of the issued and outstanding Common Shares.

No director, officer or shareholder holding sufficient securities of the Corporation to affect materially the control of the Corporation, a personal holding company of any such person, or a company for which such person is or has acted as a director or executive officer that while such person was acting in that capacity, or within a year of the person ceasing to act in that capacity is or has, within the 10 years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or been subject to any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of such person, except as hereinafter set forth. Colin M. Evans made a proposal involving Canada Revenue Agency under the *Bankruptcy and Insolvency Act* (Canada) on February 24, 2005, which was approved by the Court of Queen's Bench (Alberta) on May 18, 2005. Richard A. Gusella was a director and officer of Carmanah Resources Ltd. ("**Carmanah**") until May, 2000. A receiver was appointed to hold Carmanah's assets on January 16, 2001, approximately eight months after Mr. Gusella resigned as an officer and director of Carmanah.

## **AUDIT COMMITTEE**

### **Composition and Qualifications**

The Corporation's Audit Committee consists of three outside and independent directors namely, Messrs. Bessell, (Chair), Seth and Evans. The Board has determined that all of the members of the Audit Committee are "financially literate" as defined in Multilateral Instrument 52-110. An individual is considered financially literate if he has the ability to read and understand a set of financial statements that present a breadth and complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the issuer's financial statements. In addition, D. Hugh Bessell has, based upon his experience and educational background, been determined by the Board to be an "audit committee financial expert". The education and experience of each member of the Corporation's Audit Committee relevant to the performance of his responsibilities are as set forth below:

#### *D. Hugh Bessell, Chair*

Mr. Bessell is a chartered accountant by training and has an extensive accounting background. He retired as a partner of KPMG LLP in December, 1999 after holding the position of Deputy Chairman and Chief Operating Officer, which position he held for approximately six years. He spent a total of 33 years with KPMG LLP and its predecessor firms, and was Managing Partner of the firm's Calgary office immediately prior to assuming the role of Deputy Chairman in 1993. Mr. Bessell was a member of the Council of the Institute of Chartered Accountants of Alberta and served as its President for a period of time. Mr. Bessell has been granted the FCA designation by both the Alberta and the Ontario Institutes of Chartered Accountants in recognition of his support and contributions to his profession and community. His expertise is particularly important in his capacity as Chairman of the Corporation's Audit Committee and Mr. Bessell has been determined to be an "audit committee financial expert".

#### *W.C. (Mike) Seth*

Mr. Seth is an engineer by training and holds a Bachelors of Science Degree in Mechanical Engineering from the University of British Columbia. He is President of Seth Consultants Ltd., a private consulting firm, and prior thereto he served as Chairman of McDaniel & Associates Consultants Ltd., one of the pre-eminent oil and natural gas reserve evaluators in Canada and internationally. Prior to becoming Chairman of McDaniel Mr. Seth

was President and Managing Director of McDaniel for 25 years. Mr. Seth serves on the boards of various other junior oil and gas companies (reporting and non-reporting issuers) and of one senior oil and gas income fund. He is also the founder and a director of Energy Navigator Inc., a private software development firm servicing the petroleum industry.

*Colin M. Evans*

Mr. Evans holds a Bachelors Degree in Economics from the University of Alberta and has had an extensive business career in most facets of the oil and gas industry since the mid 1960's. He has worked in positions of increasing responsibility with both large and small private and public companies. He has also worked in the Canadian securities industry and more recently has advised a variety of oil companies on both operational and financial matters. Mr. Evans is currently Vice President, Finance of Milestone Exploration Inc., a private oil and natural gas exploration and production company. From 1994 to 2004 Mr. Evans was the President of Evans & Co. Inc., a private consulting corporation providing financial and operating advisory services to oil and gas corporations.

Mr. Evans served as Chair of the Corporation's Audit Committee from March 23, 2005 to December 1, 2005.

**Responsibilities and Terms of Reference**

The Audit Committee reviews with management and the external auditors, and recommends to the board of directors for approval, the annual financial statements of the Corporation and the reports of the external auditors thereon, the interim financial statements of the Corporation and related financial reporting, including management's discussion and analysis and earnings press releases on the annual and interim financial statements of the Corporation. The Audit Committee reviews and establishes, in conjunction with the external auditors and management, audit plans and procedures and meets with the auditors independently of management when considered appropriate. The Audit Committee is responsible for reviewing auditor independence, approving all non-audit services, reviewing and making recommendations to the board of directors on internal control procedures and management information systems. In addition, the Committee is responsible for assessing and reporting to the Board on financial risk management positions. Set out as Schedule D is the text of the Audit Committee's charter.

All permissible categories of non-audit services require pre-approval from the Audit Committee.

**External Auditor Service Fees**

The following summarizes the total fees billed by Deloitte & Touche LLP, the external auditor of the Corporation, for the years ended December 31, 2007 and December 31, 2006:

	<u>2007</u>	<u>2006</u>
Audit fees	\$ 322,000	\$ 136,943
Audit-related fees	-	-
Tax fees	-	-
All other fees <sup>(1)</sup>	89,700	88,301
<b>TOTAL</b>	<u>\$ 411,700</u>	<u>\$ 225,244</u>

**Note:**

(1) Services related to corporate and property acquisitions and prospectus financings.

Deloitte & Touche LLP are independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

**PERSONNEL**

As at December 31, 2007, the Corporation had 38 employees at its head office in Calgary, 38 field employees and 101 employees at its Refinery in Great Falls, Montana.

## DESCRIPTION OF CAPITAL STRUCTURE

The Corporation is authorized to issue an unlimited number of Common Shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares (together, "**Preferred Shares**"), issuable in series, 100,050 4.75 percent convertible senior unsecured debentures ("**Debentures**") and up to US\$600,000,000 aggregate amount of 8 year second lien notes ("**Notes**") of which as at December 31, 2007, 209,971,257 Common Shares, no Preferred Shares, \$100,050,000 aggregate principal amount of Debentures and \$US600,000,000 aggregate amount of Notes were issued and outstanding. The following is a summary of the rights, privileges, restrictions and conditions attaching to the Common Shares, Preferred Shares, Debentures and Notes.

### Common Shares

The holders of Common Shares are entitled to: dividends if, as and when declared by the board of directors; to one vote per share at meetings of the holders of Common Shares of the Corporation; and upon liquidation, dissolution or winding up of the Corporation to receive pro rata the remaining property and assets of the Corporation, subject to the rights of shares having priority over the Common Shares. All of the Common Shares currently outstanding are fully-paid and non-assessable.

At the Corporation's annual and special meeting of shareholders held on May 10, 2007 the shareholders of the Corporation adopted a shareholder rights plan (the "**Rights Plan**"), all as described in the material change report of the Corporation dated May 15, 2007. The objectives of the Rights Plan are to ensure, to the extent possible, that all shareholders of the Corporation are treated equally and fairly in connection with any takeover bid or similar offer for all or a portion of the Common Shares of the Corporation. The Rights Plan discourages discriminatory, coercive or unfair takeovers of the Corporation and gives the Board of Directors time if, in the circumstances, the Board of Directors determines it is appropriate to take such time, to pursue alternatives to maximize shareholder value in the event an unsolicited takeover bid is made for all or a portion of the outstanding Common Shares of the Corporation.

In connection with the adoption of the Rights Plan by shareholders, the Corporation issued one right in respect of each Common Share outstanding at the close of business on May 10, 2007 (the "**Record Time**") and authorized the issuance of one right in respect of each additional Common Share issued after the Record Time. The rights trade with and are represented by Connacher's Common Share certificates, including certificates issued prior to the Record Time. Readers may obtain a copy of the Rights Agreement governing the Rights Plan by accessing the Corporation's publicly filed documents, including the Rights Agreement, on SEDAR at [www.sedar.com](http://www.sedar.com).

### Preferred Shares

The Preferred Shares are issuable in series and each class of Preferred Shares will have such rights, restrictions, conditions and limitations as the board of directors may from time to time determine. The holders of Preferred Shares are entitled, in priority to holders of Common Shares, to be paid rateably with holders of each other series of Preferred Shares the amount of accumulated dividends, if any, specified to be payable preferentially to the holders of such series and upon liquidation, dissolution or winding up of the Corporation, to be paid rateably with holders of each other series of Preferred Shares the amount, if any, specified as being payable preferentially to holders of such series.

### Debentures

The Debentures were issued on May 25, 2007. See "General Development of the Corporation". The Debentures mature June 30, 2012 unless converted prior to that date and bear interest at an annual rate of 4.75 percent payable semi-annually on June 30 and December 31. The Debentures are convertible at any time into Common Shares at the option of the holder at a conversion price of \$5.00 per Common Share. The Debentures are redeemable by the Corporation on or after June 30, 2010, in whole or in part, at a redemption price equal to 100 percent of the principal amount of the Debentures to be redeemed plus accrued and unpaid interest provided that the market price of the Common Shares is at least 120 percent of the conversion price of the Debentures.

## Notes

The Notes were issued on December 3, 2007 and mature on December 15, 2015. See "General Development of the Corporation". The Notes bear interest at 10.25 percent per year. Semi-annual interest payments are due June 15 and December 15 of each year, with the final payment on December 15, 2015. The Corporation may redeem up to 35 percent of the aggregate principal amount of the Notes prior to December 15, 2010 with the net proceeds of certain equity offerings, provided at least 65 percent of the aggregate principal amount of the Notes remain outstanding after the redemption and subject to limitations contained in the Corporation's senior secured credit facilities. At any time prior to December 15, 2011 the Corporation may redeem the Notes in whole or in part at their principal amount, plus the applicable premium and accrued interest. After December 15, 2011, the Corporation may redeem some or all of the Notes at certain specified redemption prices. The Corporation may also redeem the Notes in certain other limited circumstances, including in the event of certain tax law changes. The Notes are general senior obligations and rank equally in right of payment with all of the Corporation's existing and future indebtedness that is not subordinated in right of payment of the Notes, rank senior to all the Corporation's future subordinated indebtedness and effectively are subordinated to all existing and future secured indebtedness of the Corporation and of its restricted subsidiaries, including the Revolving Facility. See "General Development of the Corporation". The Notes are secured by a second ranking charge over all of the existing and future property of the Corporation and its restricted subsidiaries, excluding the Corporation's equity interest in Petrolifera and the existing assets of Great Divide Pipeline Corporation.

### CREDIT RATINGS

The Notes are currently rated by two separate agencies, Moody's Investor Service ("**Moody's**") and Standard and Poors ("**S&P**"). Please refer to the table below for the respective ratings assigned to the Notes.

<b>Moody's</b>	<b>S&amp;P</b>
B1	BB

The Corporation is currently rated by Moody's and S&P. Please refer to the table below for the respective ratings assigned to the Corporation.

<b>Moody's</b>	<b>S&amp;P</b>
B1	BB-

**Moody's Rating Definition** – Moody's long-term obligation ratings are opinions of the relative credit risk of fixed-income obligations with an original maturity of one year or more. They address the possibility that a financial obligation will not be honoured as promised. Such ratings reflect both the likelihood of default and any financial loss suffered in the event of default. Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification from Aaa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a midrange ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category. Investment grade under the Moody's rating system would be Baa3 and higher. Obligations rated B are judged to have speculative elements and are subject to substantial credit risk.

**S&P Rating Definition** – Obligations rated BB are regarded as having significant speculative characteristics. An obligation rated BB is less vulnerable to non-payment than other speculative issues. However, it faces major ongoing uncertainties or exposure to adverse business, financial, or economic conditions which could lead to the obligor's inadequate capacity to meet its financial commitment on the obligation. BB is one notch below that which is considered "Investment Grade" (BBB- and higher) under the S&P rating system. S&P appends + and - modifiers to each generic rating classification from AAA to CCC. The modifier + indicates that the obligation ranks in the higher end of its generic rating category; a rating without a modifier indicates that the obligation ranks in the middle of its generic rating category; and the modifier - indicates that the obligation ranks in the lower end of its generic rating category.

A security rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the rating organization.

## PRIOR SALES

An aggregate of US\$600,000,000 of Notes were sold during the year ended December 31, 2007. The Notes were sold at a price of 98.657%. The Notes were the only unlisted securities of the Corporation sold during the 2007 year.

## DIVIDEND POLICY

The Corporation has not declared or paid any dividends on its Common Shares since incorporation. Any decision to pay dividends on the Common Shares will be made by the board of directors on the basis of the Corporation's earnings, financial requirements and other conditions that the board of directors may consider appropriate in the circumstances.

## MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX under the trading symbol "CLL". The following table sets out the high and low price for, and the volume of trading in, the Common Shares on the TSX, as reported by the TSX, on a monthly basis for the financial year ended December 31, 2007.

	Volume (000's)	Monthly Price Range	
		High (\$)	Low (\$)
January	16,590,933	3.69	3.07
February	22,989,312	4.13	3.50
March	15,711,274	3.98	3.47
April	25,764,015	4.43	3.66
May	20,976,719	4.13	3.67
June	14,420,923	3.83	3.49
July	20,505,952	4.40	3.71
August	24,985,285	4.16	3.20
September	25,448,165	4.30	3.61
October	20,332,853	4.08	3.76
November	16,937,274	4.04	3.39
December	14,927,526	3.79	3.31

The Debentures are listed and posted for trading on the TSX under the trading symbol "CLL.DB". The following table sets out the high and low price for, and the volume of trading in, the Debentures on the TSX, as reported by the TSX, on a monthly basis from the date of listing to December 31, 2007.

	Volume (000's)	Monthly Price Range	
		High (\$)	Low (\$)
May	177,930	103.49	100.00
June	118,700	104.99	99.92
July	115,330	112.41	104.00
August	104,480	108.75	96.30
September	62,500	106.95	99.70
October	1,890	105.22	102.00
November	111,860	104.00	94.90
December	199,890	96.25	93.50

**Note:**

(1) The Debentures began trading on the TSX on May 25, 2007.

## TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Connacher Shares and Debentures is Valiant Trust Company at its principal office in Calgary, Alberta and BNY Trust Company of Canada at its principal office in Toronto, Ontario.

### RISK FACTORS

#### Risks Relating to the Great Divide Pod One Project

***The Pod One project at Great Divide recently commenced operations, but there remains a risk that the Corporation may have interruptions of operations or increased costs.***

Construction of Pod One at Great Divide was completed in August 2007, but there remains a risk that the Corporation may experience interruptions of operations or increased costs due to many factors, including, without limitation:

- facility performance falling below expected levels of output or efficiency;
- breakdown or failure of equipment or processes;
- reservoir performance;
- errors in construction affecting operations;
- labor disputes, disruptions or declines in productivity;
- increases in materials or labor costs;
- non-performance by, or financial failure of, third party contractors;
- disruption or delays in availability of transportation services;
- energy supply disruption;
- conditions imposed by regulatory approvals;
- increased royalty payments based on the price of WTI crude oil or further changes to royalty regimes;
- shortages of, or delays in, accessing required equipment and services;
- permit requirement violation;
- transportation or operations accidents;
- delays or suspension of operations induced by weather; and
- catastrophic events such as fire, earthquakes, storms or explosions.

If any of the above events occur, it could have a material adverse effect on the Corporation's business, financial condition and results of operations.

***If the Corporation's Pod One SAGD facilities do not operate as planned the Corporation's revenue, cash flow and earnings may be reduced.***

The performance of the Corporation's Pod One SAGD facilities may differ from the Corporation's expectations. The variances from the Corporation's expectations may include, without limitation:

- the ability to operate at the expected level of throughput or production; and
- the reliability or availability of the facilities.

If the facilities do not perform to the Corporation's expectations or as required by regulatory approvals, the Corporation may be required to invest additional capital to correct deficiencies or the Corporation may not be able to produce the expected level of production. If these expectations are not met, the Corporation's revenue, cash flow and earnings could be reduced.

***The operating costs of the Great Divide Pod One project may vary considerably during the operating period. If they increase, the Corporation's earnings and cash flow may be reduced.***

The operating costs of the Great Divide Pod One project may vary considerably during the operating period. If such costs increase, the Corporation's earnings and cash flow will be reduced. The factors which could affect operating costs include, without limitation:

- the cost of natural gas and electricity;
- the actual steam to oil ratio required to operate the SAGD well pairs;
- the amount and cost of labor to operate the Great Divide Pod One project;
- power outages, particularly in winter when freeze-ups could occur;
- produced sand causing erosion, hot spots and corrosion;
- reliability of the facilities;
- the maintenance cost of the facilities;
- well performance;
- workovers or the need to drill additional wells;
- the cost to transport bitumen, diluent and dilbit and the cost to dispose of certain by-products;
- the cost of insurance and the inability to insure for certain types of losses;
- catastrophic events such as fires, earthquakes, storms or explosions;
- the cost of catalyst and chemicals; and
- the cost of complying with regulatory approvals.

***Access to diluent supplies at favorable prices may be limited.***

Bitumen is characterized by high specific gravity or weight and low viscosity or resistance to flow. Diluent is required to facilitate the transportation of bitumen. A shortfall in the supply of diluent may cause its cost to increase or alternative diluent supplies to be purchased, thereby increasing the cost to transport bitumen to market and correspondingly increasing the Corporation's operating cost and negatively impacting the overall profitability of the Great Divide Pod One project.

***In-situ extraction is subject to uncertainty.***

Current SAGD technologies for in-situ recovery of heavy oil and bitumen are energy intensive, requiring significant consumption of natural gas or other fuels in the production of steam which is used in the recovery

process. The amount of steam required in the production process can also vary and impact costs. The quality and performance of the reservoir can also impact the timing and levels of production using this technology. Commercial application of this technology for bitumen is relatively new, and accordingly in the absence of long-term operating history there can be no assurances with respect to the sustainability of SAGD operations.

***The recovery of bitumen from oil sands is subject to a number of risks and uncertainties, many of which are outside of the Corporation's control.***

Recovering bitumen from oil sands involves particular risks and uncertainties. Severe weather conditions can cause reduced production and in some situations result in higher costs. SAGD bitumen recovery facilities and development and expansion of production can entail significant capital outlays. Equipment failures could result in damage to the Corporation's facilities or wells and liability to third parties against which the Corporation may not be able to fully insure or may elect not to insure because of high premium costs or for other reasons.

***Abandonment and reclamation costs relating to Great Divide Pod One may be higher than anticipated.***

The Corporation will be responsible for compliance with terms and conditions of environmental and regulatory approvals and all laws and regulations regarding the abandonment of the Great Divide Pod One project and reclamation of its lands at the end of its economic life, the cost of which may be substantial. A breach of such legislation and/or regulations may result in the imposition of fines and penalties, including an order for cessation of operations at the site until satisfactory remedies are made. It is not possible to estimate reliably the abandonment and reclamation costs since they will be a function of regulatory requirements at the time and the value of the salvaged equipment may be more or less than the abandonment and reclamation costs. In the future the Corporation may determine it prudent or be required by applicable laws or regulations to establish and fund one or more reclamation funds to provide for payment of future abandonment and reclamation costs.

***Transportation to and from Great Divide is subject to certain hazards.***

The Corporation expects that it will initially truck bitumen to market. Normal hazards associated with trucking include proximity to a busy highway (Highway 63) and traffic. The Corporation anticipates that vehicular traffic to and from the Great Divide Pod One project will be via Highway 63 for the life of the project. Collisions between vehicles and wildlife remain a significant hazard.

***Future pods at Great Divide, including pod two at Algar, will be subject to construction stage and financing risks if there are cost overruns. These expansion pods may not be completed on time, on budget or at all and once operational, may be subject to delays, interruptions or increased costs that may materially adversely affect the Corporation's results of operations.***

Future pods at Great Divide, including the Algar Project, will be subject to construction stage and financing risks. Additionally, there is a risk that future operations, including expansion of production at Great Divide, may have delays, interruption of operations or increased costs due to many factors, including, without limitation:

- shortages of, or delays in obtaining qualified labor, equipment, construction materials or services;
- labor disputes, disruptions or declines in productivity;
- changes in the scope of the project or increases in the amount or cost of materials or labor;
- contractor or operator errors in design or construction and non-performance by, or financial failure of, third party contractors;
- breakdown or failure of equipment or processes;
- delays in obtaining, or conditions imposed by, regulatory approvals;
- an inability to obtain adequate financing, or financing on terms satisfactory to the Corporation;

- transportation or construction accidents, disruption or delays in availability of transportation services or adverse weather conditions affecting construction or transportation;
- unforeseen site surface or subsurface conditions;
- disruption in the supply of energy; and
- catastrophic events such as fires, earthquakes, storms or explosions.

The Corporation's development of any additional pods at Great Divide will be subject to substantially all of the same risks as those set forth in this Annual Information Form for Pod One and the Algar Project in general.

The industry is in a period where unprecedented oil sands development and industrial activity is planned at a time when economic activity in many other sectors in the region is also high. For example, the Corporation experienced cost overruns in connection with the development of Pod One, which the Corporation believed to be modest in light of inflationary pressures and in comparison to the relative cost pressures faced by other oil sands operators in this area. The Corporation's expansion projects will need to compete for equipment, supplies, services, and labor in this environment, which could result in increased costs or, shortages of goods and services that delay progress, or both.

In addition, participation in expansion projects will significantly increase the demands on the Corporation's management and administrative resources and require significant financing. The Corporation may not be able to effectively manage or finance the expansions, and any failure to do so could have a material adverse effect on the Corporation's business, financial condition or results of operations. See "Risk Factors—Risks Related to Financing and the Corporation's Indebtedness".

#### **Risks Relating to the Corporation's Oil Sands and Conventional Operations**

*The Corporation must obtain and maintain regulatory approvals and comply with stringent environmental laws and regulations. The failure to obtain such approvals and comply with any of these laws and regulations could, among other things, prevent or limit the Corporation's operations or subject the Corporation to substantial liability, which, in turn, could have a material adverse effect on the Corporation's business and financial condition.*

The operation and decommissioning of the Corporation's projects and operations, as well as the construction of future phases of the Corporation's oil sands projects, the development of additional projects and reclamation of the lands used in the Corporation's operations, are conditional upon various environmental and regulatory approvals issued by governmental authorities. There is no assurance such approvals will be issued, or once issued, not appealed, or renewed, or that they will not contain terms and conditions which make the Corporation's projects and operations uneconomic or cause the Corporation to significantly alter its projects and operations. Further, the operation and decommissioning of the Corporation's projects and reclamation of the Corporation's lands are and will be subject to approvals, laws and regulations relating to environmental protection and operational safety. Risks of substantial costs and liabilities are inherent in both oil sands and conventional oil and natural gas production recovery and there can be no assurance that substantial costs and liabilities will not be incurred or that the Corporation's projects or conventional operations will be permitted to carry on operations. Moreover, it is possible that other developments, such as increased levels of royalties or increasingly strict environmental and safety laws, regulations and enforcement policies thereunder and claims for damages to property or persons resulting from the project's operations could result in substantial costs and liabilities to the Corporation or delays to, or abandonment of, the Corporation's projects and operations, including the Great Divide Pod One project.

No assurance can be given that future environmental approvals, processes, laws or regulations will not adversely impact the Corporation's ability to operate or expand its operations or increase or maintain its production or will not increase the Corporation's unit costs of production for crude oil, natural gas and bitumen. Canada is a signatory to the United Nations Framework Convention on Climate Change (the "**Convention**") and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide and other greenhouse gases, or GHGs. The Corporation will be a significant producer of some GHGs covered by the Convention as a result of the Corporation's Great Divide Pod One project.

On April 26, 2007 the Canadian Federal Government released a *Regulatory Framework for Air Emissions*, or the Framework, which outlines proposed new requirements governing the emission of GHGs and other industrial air pollutants, including sulphur oxides, volatile organic compounds, particulate matter, and possibly additional sector specific pollutants, in accordance with the Canadian Federal Government's *Notice of Intent to Develop and Implement Regulations and Other Measures to Reduce Air Emissions* released on October 19, 2006. On March 10, 2008 the Canadian Federal Government elaborated on the Framework with the release of its *Turning the Corner* document. It is contemplated that new regulations will take effect January 1, 2010. Draft regulations are expected to be available for public comment in the Fall of 2008.

The proposed regulatory framework provides that conventional upstream oil and gas facilities which emit 3 kilotonnes or more of GHGs and which are operated by firms with production of 10,000 barrels of oil equivalent per day and that existing oil sands facilities in operation by 2004 will be subject to an 18% emission intensity reduction requirement commencing in 2010, with 2% additional annual reductions thereafter until 2020. Emission intensity is the amount of GHG emissions per unit of production or output. Facilities commissioned between 2004 to 2011 or facilities existing prior to 2004 which between 2004 and 2011 have had a major expansion resulting in an increase of 25% or more in physical capacity or which undergo a significant change to processes will be exempt from the 2010 emissions intensity reduction target of 18% but will have to report their emissions each year and after their third year of operation will be required to reduce their emissions intensity by 2% annually from a baseline emissions standard which is to be determined by reference to a sector-specific cleaner-fuel standard. For oil sands facilities, it is contemplated that there will be specific cleaner-fuel standards based on the use of natural gas for each of mining, in situ and upgrading. However, an incentive to deploy carbon capture and storage ("CCS") has been included. CCS is where carbon dioxide is separated from a facility's process or exhaust gas emissions before they are emitted, transferred from the facility to a suitable storage location, and injected into underground geological formations and monitored to ensure they do not escape into the atmosphere. If a facility commissioned between 2004 and 2011 is built such that it is able or ready to undertake CCS, then it will be exempt from the cleaner-fuel standard until 2018 and it will only be required to reduce its emission-intensity by 2% per year from its actual emissions. In situ oil sands projects and oil sands upgraders built after 2011 must have their GHG emissions profiles by 2018 equivalent to that of facilities employing CCS technology. The proposed regulatory framework further encourages widespread use of CCS by 2018 by crediting emitters that make use of CCS technology for investments in pre-certified CCS projects up to 100% of their regulatory obligations through 2017.

The proposed compliance mechanisms include an emissions credit trading system for GHGs and certain industrial air pollutants, and several options for companies to choose among to meet GHG emission intensity reduction targets and encourage the development of new emission reduction technologies, including the option of making payments into a technology fund, an emissions and offset trading system, limited credits for emission reductions created between 1992 and 2006, and international emission credits under the clean development mechanism under the Kyoto Protocol for up to 10% of each firm's regulatory obligation.

These future federal industrial air pollutant and GHG emission reduction targets, together with provincial emission reduction requirements in Alberta's *Climate Change and Emissions Management Act*, or emission reduction requirements in future regulatory approvals, will require the reduction of emission intensity from the Corporation's operations and facilities, payments to a technology fund or purchase of emission reduction or off-set credits. The required emission intensity reductions may not be technically or economically feasible to implement for the Great Divide Pod One project or the Corporation's conventional oil and natural gas activities and the failure to meet such emission intensity reduction requirements or other compliance mechanisms may materially adversely affect the Corporation's business and result in fines, penalties and the suspension of operations. As well, equipment from suppliers which can meet future emission standards may not be available on an economic basis and other compliance methods of reducing emission intensity to required levels in the future may significantly increase the Corporation's operating costs or reduce output of the project. The Corporation may not be able for technical or economic reasons to take advantage of the incentives to implement CCS. Emission reduction or off-set credits may not be available for acquisition by the project or may not be available on an economic basis. There is also the risk that the governments could impose additional emission or emission intensity reduction requirements, or that the federal and/or provincial governments could pass legislation which would tax such emissions.

To operate the facilities, the Great Divide Pod One project relies on non-potable subsurface water, which is obtained under licenses from Alberta Environment. There can be no assurance that the licenses to withdraw subsurface water will not be rescinded or that additional conditions will not be added to these licenses. There can be

no assurance that the Corporation will not have to pay a fee for the use of water in the future or that any such fees will be reasonable. In addition, the expansion of the project relies on securing licenses for additional water withdrawal, and there can be no assurance that these licenses will be granted on terms favorable to the Corporation or at all, or that such additional water will in fact be available to divert under such licenses.

***The Corporation's business may suffer in the event of a loss of key personnel.***

The Corporation faces numerous risks due to the stage of its development, as well as certain other factors. The Corporation's success will depend in part on the ability, expertise, judgment, discretion and good faith of the Corporation's management and its ability to retain them. The Corporation does not maintain key-man life insurance with respect to any of its employees. The loss of any key personnel, may have a material adverse effect on the Corporation's business, financial condition or results of operations.

***The Corporation's oil and gas operations are subject to numerous operational hazards and other risks against which the Corporation may not be insured.***

The operation of Pod One and, upon receipt of regulatory approval, construction and start-up at the Algar Project, the Refinery and the Corporation's conventional oil and gas properties will be subject to the customary hazards of recovering, transporting and processing hydrocarbons, such as fires, explosions, gaseous leaks, migration of harmful substances, blowouts and oil spills. A casualty occurrence might result in the loss of equipment or life, as well as injury or property damage. The Corporation will not carry insurance with respect to all potential casualty occurrences and disruptions. It cannot be assured that the Corporation's insurance will be sufficient to cover any such casualty occurrences or disruptions. The Corporation's operations could be interrupted by natural disasters or other events beyond its control. Losses and liabilities arising from uninsured or under insured events could have a material adverse effect on the Corporation's business, financial condition and results of operations.

***The labor force is limited and the Corporation may not be able to hire all of the labor force required at the compensation levels budgeted for or at all.***

The labor force in Alberta, and specifically in the Fort McMurray and surrounding area, is limited and the inability to access the necessary skilled laborers to operate Pod One and the Algar Project, construct new projects such as the Algar Project and to operate and maintain the Refinery and the Corporation's conventional crude oil and natural gas properties could have an adverse effect on the Corporation's development plans. There are other oil sands projects and expansions currently under construction and significant projects and expansions have been announced by other oil sands developers. This means the Corporation has to compete with these other projects for experienced employees and such competition may impact the availability of employees and/or may result in increases to compensation paid to such employees. In addition, rising personnel costs could result in increases in general and administrative expenses and labor costs which may adversely affect the Corporation's cash flow and earnings.

***Title review will be done in accordance with industry standards but will not guarantee title to the Corporation's properties.***

The Corporation's oil sands properties were acquired from the Crown in Right of Alberta and although title reviews will be done according to industry standards prior to the purchase of most crude oil and natural gas producing properties (excluding properties acquired from the Crown in Right of Alberta) or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which could result in a reduction of the revenue the Corporation receives. If such were the case, the Corporation's entitlement to the production and reserves associated with such leases could be jeopardized, which could have a material adverse effect on the Corporation's financial condition, results of operations and the Corporation's ability to execute its business plan in a timely manner or at all.

***Aboriginal peoples may make claims against the Corporation or its properties.***

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of western Canada. Certain aboriginal peoples have filed a claim against the Government of Canada, the Province of Alberta, certain governmental entities and the regional municipality of Wood Buffalo (which includes the City of Fort McMurray,

Alberta) claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray, including the lands on which the Great Divide Pod One project and most of the other oil sands operations in Alberta are located. Such claims, if successful, could have a significant adverse effect on the Corporation and the Great Divide Pod One project. The Corporation continues to consult with and work with Aboriginal groups at Great Divide.

### **Risks Relating to Reserves and Resources**

***The Corporation's future net revenue may be adversely affected by proposed changes to the Alberta royalty regime.***

The Corporation's reserves and resources and future net revenues associated therewith in the Connacher GLJ Report do not reflect the increased royalties contemplated by the proposed new royalty regime announced by the Alberta government on October 25, 2007. After taking the new royalty regime into account, such values may be adversely affected.

***Undue reliance should not be placed on estimates of reserves and resources, since these estimates are subject to numerous uncertainties. The Corporation's actual reserves could be lower than such estimates.***

There are numerous uncertainties inherent in estimating quantities of proved, probable and possible reserves and quantities of contingent and prospective resources and future net revenues to be derived therefrom, including many factors beyond the Corporation's control. The reserve, resource and future net revenue information set forth herein represents estimates only. The reserves, resources and estimated future net cash flow from the Corporation's properties have been independently evaluated by GLJ with an effective date of December 31, 2007. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves and resources, timing and amount of capital expenditures, marketability of production, future prices of blended bitumen, crude oil and natural gas, operating costs, abandonment and salvage values, royalties and other government levies that may be imposed over the producing life of the reserves and resources. These assumptions were based on prices in use at the date the relevant evaluations were prepared, and many of these assumptions are subject to change and are beyond the Corporation's control. Actual production and cash flow derived therefrom will vary from these evaluations, and such variations could be material.

Estimates with respect to reserves and resources that may be developed and produced in the future are often based upon volumetric calculations, probabilistic methods and upon analogy to similar types of reserves and resources, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves or resources.

Reserve and resource estimates may require revision based on actual production experience. Such figures have been determined based upon assumed commodity prices and operating costs. Market price fluctuations of crude oil and natural gas prices may render uneconomic the recovery of certain grades of bitumen. Moreover, short term factors relating to oil sands resources may impair the profitability of the Great Divide Pod One or subsequent projects in any particular period.

The present value of estimated future net revenue referred to herein should not be construed as the fair market value of estimated crude oil and natural gas reserves and resources attributable to the Corporation's properties. The estimated discounted future revenue from reserves are based upon price and cost estimates which may vary from actual prices and costs and such variance could be material. Actual future net revenue will also be affected by factors such as the amount and timing of actual production, supply and demand for bitumen, crude oil and natural gas, curtailments or increases in consumption by purchasers and changes in governmental regulations or taxation.

References to "resources," "contingent resources" and "prospective resources" in this Annual Information Form do not constitute, and should be distinguished from, references to "reserves". Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable whereas contingent resources are those quantities of petroleum estimated, as of a given date, to be

potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

***The Corporation's cash flow and earnings are highly dependent upon the Corporation developing and increasing its current reserve and resource base and discovering or acquiring additional reserves and resources.***

The Corporation's reserves, resources and production, and therefore the Corporation's cash flow and earnings, are highly dependent upon it developing and increasing its current reserve and resource base and discovering or acquiring additional reserves and resources. Without the addition of reserves and resources through exploration, acquisition or development activities, the Corporation's reserves, resources and production will decline over time as reserves and resources are depleted. To the extent that cash flow from operations is insufficient and external sources of capital become limited or unavailable, the Corporation's ability to make the necessary capital investments to maintain and expand its reserves and resources will be impaired. There can be no assurance that the Corporation will be able to find and develop or acquire additional reserves and resources to replace production at commercially feasible costs.

### **Risks Relating to the Refinery**

***The Corporation's refining operations and sales are subject to a number of seasonal factors which may impact its financial performance.***

The Refinery is subject to a number of seasonal factors which may cause product sales revenues to vary throughout the year. The Refinery's primary asphalt market is paving for road construction which is predominantly a summer demand. Consequently, prices and volumes for the Corporation's asphalt tend to be higher in the summer and lower in the colder seasons and during the winter most of the Refinery's asphalt production is stored in tackage for sale in the subsequent summer. Seasonal factors also affect the prices of gasoline, for which demand is generally higher in summer months, and distillate and diesel, for which demand is generally higher in winter months. As a result, inventory levels, sales volumes and prices can be expected to fluctuate on a seasonal basis.

***Refinery operations are subject to numerous operational hazards and other risks against which the Corporation may not be insured. These risks may interrupt operations, damage facilities or personnel, or interrupt cash flow.***

The operation of the Refinery will be subject to the customary hazards of transporting and processing hydrocarbons, such as fires, explosions, gaseous leaks, migration of harmful substances, or oil and product spills. As well the Corporation could experience significant losses as a result of catastrophic events such as fire, flood, earthquakes, or storms. A casualty occurrence might result in the loss of equipment or life, as well as injury or property damage. The Corporation will not carry insurance with respect to all potential casualty occurrences and disruptions. It cannot be assured that the Corporation's insurance will be sufficient to cover any such casualty occurrences or disruptions. The Corporation's operations could be interrupted by natural disasters or other events beyond its control. Losses or liabilities arising from uninsured or under insured events could have a material adverse effect on the Refinery and on the Corporation's business, financial condition and results of operations.

***Abandonment costs relating to the Refinery have not been estimated and recorded.***

The Corporation has not recorded an asset retirement obligation for the Refinery as it is currently the Corporation's intent to maintain and upgrade the Refinery so that it will be operational for the foreseeable future. Consequently, it is not possible at the present time to estimate a date or range of dates for settlement of any asset retirement obligation related to the Refinery.

***The Corporation's volatility of Refinery margins will fluctuate with changes in the supply and demand for refined products and certain other factors.***

The Corporation will face certain risks associated with the volatility of refinery margins. Refinery operations are sensitive to wholesale and retail margins for refined products, including asphalt, jet fuel, diesel and gasoline. Margin volatility is influenced by overall marketplace competitiveness, the operation of other refineries within the Corporation's market area, weather, the cost of crude oil and fluctuations in supply and demand for refined products.

***New U.S. government standards on content of refined products may result in substantial capital expenditures to meet environmental regulations.***

An initiative of the U.S. Environmental Protection Agency on gasoline would impose reductions in benzene content, volatility, sulphur, and other parameters. U.S. Congress is also proposing a number of environmental initiatives related to greenhouse gases and biofuels. These new requirements, other requirements of the *U.S. Federal Clean Air Act*, or other presently existing or future environmental regulations could require the Corporation to expend substantial amounts to permit the Refinery to produce products that meet such requirements.

### **Risks Relating to Commodity Pricing and Exchange Rate Fluctuations**

***The Corporation's results of operations will depend upon the prevailing prices of crude oil and natural gas in the worldwide markets. Those prices can fluctuate substantially.***

The Corporation's revenues, cash flow, earnings, cost of capital, asset values, results of operations and financial condition are dependent upon the prevailing price of crude oil and natural gas, heavy oil differentials and the related products that the Corporation produces at the Refinery. Crude oil prices have historically been extremely volatile and fluctuate significantly in response to regional, national and global supply and demand factors beyond the Corporation's control. Among the factors that can cause crude oil price and natural gas price fluctuations are:

- the level of consumer product demand;
- the domestic and foreign supply of crude oil and natural gas, including the decisions of the Organization of Petroleum Exporting Countries relating to export quotas and their compliance or non-compliance with such self-imposed quotas;
- weather conditions, including hurricanes, floods and other natural disasters;
- domestic and foreign governmental regulations;
- the effect of worldwide conservation of resources;
- new bitumen, crude oil and natural gas discoveries;
- Third World economic growth;
- the price and availability of alternative fuels, including liquefied natural gas;
- political conditions in crude oil and natural gas producing regions, including terrorist activities and other hostilities;
- the proximity of reserves to, and capacity of, transportation facilities;
- the price of foreign imports of crude oil and natural gas;
- overall global and domestic economic conditions; and

- concern over climate change or GHG emissions.

Any material decline in prices could result in a material reduction of the Corporation's operating and financial results, production revenue, reserves and overall value. In addition, any prolonged period of low oil prices could result in a decision by the Corporation to suspend or reduce production. Any such suspension or reduction of production would result in a corresponding substantial decrease in the Corporation's revenues and earnings and could materially impact the Corporation's ability to meet its debt servicing obligations and could expose the Corporation to significant additional expense as a result of any future long-term contracts. If production was not suspended or reduced during such period, the sale of the petroleum products produced by the Corporation at such reduced prices would lower its revenues.

The Corporation conducts an assessment of the carrying value of its assets to the extent required by GAAP. If crude oil and/or natural gas prices decline, the carrying value of the Corporation's assets could be subject to downward revision and the Corporation's earnings could be adversely affected.

***The Corporation will be subject to foreign currency exchange fluctuation exposure.***

Revenue received from the sale of crude oil is generally referenced to a price denominated in U.S. dollars. All of the Refinery's business is conducted in U.S. dollars. Additionally, the Notes are denominated in U.S. dollars. As the Corporation reports its financial results as contained in its balance sheet, income statement and statement of cash flows in Canadian dollars, fluctuations in the rate of exchange between the U.S. dollar and Canadian dollar could materially affect reported results.

***Risks Relating to Hedging Activities***

The Corporation continually evaluates the use of, and often employs derivative structures to hedge commodity, interest rate and foreign exchange risk. Risks associated with such products, include but are not limited to counterparty risk, settlement risk, basis risk, liquidity risk and market risk which could impair or negate the hedging strategy with consequent negative impact on earnings and cash flow.

***Risks Relating to Third Parties***

***The Corporation is subject to extensive government regulation. The Corporation may have to expend substantial amounts for compliance with regulations or the Corporation may become liable for failure to comply with regulations.***

The oil and gas industry in Canada, including the oil sands industry, operates under Canadian federal, provincial and municipal legislation and regulation governing such matters as land tenure, prices, royalties, production rates, environmental protection controls, income, the exportation of crude oil, natural gas and other products, the use of sub-surface water in the Corporation's operations, as well as other matters. The industry is also subject to regulation by federal, provincial and municipal governments in such matters as the awarding or acquisition of exploration and production rights, oil sands or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields and mine sites (including restrictions on production) and possibly expropriation or cancellation of contract rights.

Government regulations may be changed from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations affecting the crude oil and natural gas industry could reduce demand for crude oil and natural gas, increase the Corporation's costs and have a material adverse impact on the Corporation.

To date, the Corporation believes Pod One has received all of the approvals currently required. However, before proceeding with future phases at Great Divide, the Corporation must obtain all required regulatory approvals. The regulatory approval process can involve stakeholder consultation, environmental impact assessments, public hearings and appeals to tribunals and courts, among other things. In addition, regulatory approvals may be subject to conditions including security deposit obligations and other commitments. Failure to obtain regulatory approvals, or failure to obtain them on a timely basis, could result in delays or restructuring of the project and increased costs, all

of which could have a material adverse affect on the Corporation. The Great Divide Pod One project and ongoing exploration activity is also subject to periodic inspections by regulatory authorities to ensure the Corporation's compliance with the conditions of regulatory approvals. Negative inspection results may lead to the imposition of fines or penalties or the suspension or rescission of the project's regulatory approvals.

***The Corporation's operating cash flow will be directly affected by the applicable royalty regime.***

The Government of Alberta receives royalties on production of natural resources from lands in which it owns the mineral rights. On October 25, 2007, the Government of Alberta unveiled a new proposed royalty regime. The new regime would introduce new royalties for conventional oil, natural gas and oil sands effective January 1, 2009 that are linked to price and production levels and would apply to both new and existing oil sands projects.

Currently, in respect of oil sands projects having regulatory approval, a royalty of one percent of gross bitumen revenue is payable prior to the payout of specified allowed costs, including certain exploration and development costs, operating costs and a return allowance. Once such allowed costs have been recovered, a royalty of the greater of: (a) one percent of gross bitumen revenue; and (b) 25 percent of net bitumen revenue (calculated as gross bitumen revenue less operating costs and additional capital expenditures incurred since payout, referred to as net royalty), is levied. Net royalties payable pursuant to Crown petroleum and natural gas leases are ad valorem royalties, assessed on a sliding scale where the rate changes depending on oil or natural gas prices and the level of production. Crown royalties currently range from 15 to 35 percent in the case of conventional oil, five to 35 percent in the case of natural gas and from 15 to 50 percent in the case of natural gas liquids.

Under the proposed royalty regime, the Government of Alberta would increase its royalty share from oil sands development by introducing price sensitive formulas which would be applied both before and after specified allowed costs have been recovered. The base royalty would start at one percent and would increase for every dollar that world oil price, as reflected by the WTI crude oil price (converted to Canadian dollars), is priced above \$55 per barrel, to a maximum of nine percent when the WTI crude oil price is \$120 per barrel or higher. The net royalty on oil sands would start at 25 percent and would increase for every dollar the WTI crude oil price is above \$55 per barrel to 40 percent when the WTI crude oil price is \$120 per barrel or higher. The Government of Alberta has announced that it intends to review, and if necessary, revise current rules and enforcement procedures with a view to clearly defining what expenditures would qualify as specified allowed costs.

The new royalty formula for conventional oil would operate on a sliding rate formula containing separate elements that account for oil price and well production. Royalty rates for conventional oil would range up to 50 percent, with rate caps once the price of conventional oil reaches \$120 per barrel.

Under the proposed royalty regime, natural gas royalties would be set by a sliding rate formula sensitive to price and production volume. New natural gas royalty rates would range from five percent to 50 percent with rate caps once the price of natural gas reaches \$17.50/mmbtu. Royalties for natural gas liquids would be set at 40 percent for pentanes and 30 percent for butanes and propane.

The implementation of the proposed changes to the royalty regime in Alberta is subject to certain risks and uncertainties. The significant changes to the royalty regime require new legislation, changes to existing legislation and regulation and development of proprietary software to support the calculation and collection of royalties. Additionally, certain proposed changes contemplate further public and/or industry consultation. There may be modifications introduced to the proposed royalty structure prior to the implementation thereof.

An increase in royalties would reduce the Corporation's earnings and could make future capital expenditures or the Corporation's operations uneconomic and could, in the event of a material increase in royalties, make it more difficult to service and repay the Corporation's debt. Any material increase in royalties would also significantly reduce the value of the Corporation's associated assets.

***The Corporation's operations, including the Great Divide Pod One project, will depend on infrastructure owned and operated by third parties and on services provided by third parties. Failure by these third parties to provide infrastructure and services required by the Corporation could have a material adverse effect on the Corporation's business and results of operations.***

The Corporation depends on certain infrastructure owned and operated or to be constructed by others and on services provided by third parties, including, without limitation, processing facilities, pipelines for the transportation of products to the market, natural gas, disposal pipelines and electrical grid transmission lines for the provision and/or sale of electricity to the Corporation. The failure of any or all of these third parties to supply utilities, services, or in connection with the Great Divide Pod One and subsequent projects including the Algar Project, to construct necessary infrastructure, on a timely basis and on acceptable commercial terms will negatively impact the Corporation's operations and financial results. Generally, the Corporation also depends on third parties to provide numerous services to it in connection with its Refinery and conventional crude oil and natural gas operations, including transportation services, drilling and well services, and the failure of such third parties to provide such services will also negatively impact the Corporation's operations and financial results.

The Corporation plans on trucking diluent to, and dilbit from, Pod One to markets in the short term. The ability to deliver diluent to Pod One and ship dilbit to markets is dependant on, among other things, access to trucks and drivers, accidents, weather delays and general road conditions. Delays or the inability to deliver diluent to Pod One or ship dilbit to market could have a negative impact on the Corporation's results of operations and cash flow.

***Changes in tax laws may adversely affect the Corporation, the Great Divide Pod One project and future expansion phases.***

Income tax laws or government incentive programs relating to the oil and gas industry and in particular the oil sands sector may in the future be changed or interpreted in a manner that adversely affects the Corporation, its operations and future expansion plans.

***The Corporation's industry is highly competitive and many of its competitors have greater resources than the Corporation does.***

The Canadian and international petroleum industry is highly competitive in all aspects, including the exploration for, and the development of, new sources of supply, the acquisition of crude oil and natural gas interests and the distribution and marketing of petroleum products. The Corporation will compete with producers of bitumen, synthetic crude oil blends and other producers of conventional crude oil and natural gas. Some of the conventional producers have lower operating costs than the Corporation is anticipated to have, and many of them have greater resources than the Corporation has. Certain of the Corporation's competitors may have greater resources to source, attract, and retain the personnel, materials and services that the Corporation will require to conduct its operations or to conduct expansions of the Refinery or at Great Divide. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

A number of companies other than the Corporation's company have announced plans to enter the oil sands business and begin production of bitumen, or expand existing operations. Expansion of existing operations and development of new projects could materially increase the supply of bitumen or synthetic crude oil and other competing crude oil products in the marketplace. Depending on the levels of future demand, increased supplies could have a negative impact on prices of bitumen and, accordingly, the Corporation's results of operations and cash flow.

#### **Risks Relating to The Corporation's Investment In Petrolifera**

***The Corporation is subject to foreign political, economic and other uncertainties relating to its investment in Petrolifera.***

Petrolifera's operations may be adversely affected by changes in government policies and legislation or social instability and other factors which are not within the control of Petrolifera including, among other things, a change in crude oil or natural gas pricing policy, the risks of war, terrorism, abduction, expropriation, nationalization, renegotiation or nullification of existing concessions and contracts, taxation policies, economic

sanctions, the imposition of specific drilling obligations and the development and abandonment of fields. In addition, the crude oil and natural gas produced by Petrolifera in Argentina must be sold locally at rates that may not be comparable to international rates.

Petrolifera's results of operation and the value of the Corporation's investment in Petrolifera, are subject to political, economic, and other uncertainties, including, but not limited to, expropriation, changes in energy policies or the personnel administering them, currency fluctuations and devaluations, exchange controls and royalty and tax increases. In the event of a dispute arising in connection with Petrolifera's operations in Argentina, Peru or Colombia, Petrolifera may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdictions of the courts of Canada or enforcing Canadian judgements in such other jurisdictions. Petrolifera may also be hindered or prevented from enforcing its rights with respect to a governmental instrumentality because of the doctrine of sovereign immunity. Accordingly, Petrolifera's exploration, development and production activities in Argentina, Peru and Colombia could be substantially affected by factors beyond Petrolifera's control, any of which could have a material adverse effect on Petrolifera's results of operations, which would have an impact on the Corporation's results of operations, and on the value of the Corporation's investment.

***Through the Corporation's investment in Petrolifera the Corporation may have indirect exposure to short-term asset backed commercial paper investments in Canada.***

The Corporation accounts for its 26 percent investment in Petrolifera using the equity method basis of accounting. Accordingly, the Corporation's financial results include its 26 percent interest in Petrolifera's earnings or losses. On August 20, 2007, Petrolifera advised the Corporation and other shareholders and market participants of its exposure to short-term asset backed commercial paper ("ABCP") investments in Canada. During August 2007 these investments became due and payable and were not repaid. As at July 31, 2007, Petrolifera had approximately \$37.7 million of its total cash and cash equivalents invested in notes issued by two separate trusts in the ABCP markets. Subsequently Petrolifera reclassified its ABCP investments to long term and recorded a non-cash impairment which reduced the carrying value of its ABCP investment and also resulted in lower earnings in 2007. As the Corporation uses the equity method to account for its investment in Petrolifera, this amount was lowered by the extent of the Corporation's equity interest in the after tax impairment. There is no assurance as to the outcome of the restructuring process and the actual timing and amount ultimately recoverable from Petrolifera's investment in ABCP may differ materially from Petrolifera's estimate of such value at December 31, 2007 which would impact Petrolifera's earnings in future periods. To the extent that Petrolifera is unsuccessful in its efforts to recover its investment in full, Petrolifera may suffer a loss and the Corporation will be required to account for its proportion of such loss in accordance with its accounting policies.

***The Corporation does not control the board of directors of Petrolifera, and accordingly Petrolifera may take actions contrary to those desired by Connacher.***

The Corporation owns 26 percent of the outstanding common shares of Petrolifera and currently has three representatives, including its Chief Executive Officer, who is also the Executive Chairman of Petrolifera, on the board of directors. The Corporation's ownership is not sufficient to elect a majority of the board of directors and the Corporation has no contractual rights related thereto. Additionally, Petrolifera's management is independent of the Corporation's management with the exception that Richard A. Gusella is Executive Chairman of Petrolifera and Connacher's President and Chief Executive Officer. The directors and officers of Petrolifera have a fiduciary obligation to act in the best interest of Petrolifera. As such, decisions made by the directors and/or officers of Petrolifera may cause Petrolifera to undertake strategies or courses of action that may not be consistent with the Corporation's short or long term objectives.

In addition, if Mr. Gusella is unable to devote his full time and undivided attention to the Corporation's affairs it may have a material adverse effect on the company.

## **Risks Relating to Financing and the Corporation's Indebtedness**

***If the Corporation is unable to obtain sufficient funding the Corporation's ability to expand its operations may be impaired.***

Depending on future exploration, development, acquisition and divestiture plans, including additional projects at the Corporation's oil sands properties in the Great Divide and Halfway Creek regions and the operations and capacity of the Refinery, the Corporation will require additional financing, and in the case of expansions of the Refinery and for further oil sands development, the amounts of such financing will be significant. The Corporation's ability to arrange such financing in the future will depend in part upon the prevailing capital market conditions as well as the Corporation's business performance. There can be no assurance that the Corporation will be successful in its efforts to arrange additional financing on terms satisfactory to the Corporation or at all. If the Corporation obtains additional financing by the issuance of shares from treasury, control of the Corporation may change and shareholders may suffer additional dilution.

From time to time the Corporation may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase Connacher's debt levels above industry standards.

***The Corporation borrows funds in U.S. dollars.***

A significant portion of the Corporation's debt is denominated in U.S. dollars. Fluctuations in exchange rates may significantly increase or decrease the amount of debt recorded on the Corporation's financial statements. The Corporation often employs derivative structures to hedge foreign exchange risk. See "Risk Factors - Risks Relating to Hedging Activities."

***The Corporation's ability to make scheduled repayments or to re-finance its debt obligations will depend upon the Corporation's financial and operating performance.***

The Corporation intends to use a revolving credit facility to finance its conventional, oil sands and refining expenditures. Restrictive covenants governing the Corporation's debt will limit the amount of debt that the Corporation may incur. The Corporation's ability to make scheduled repayments or to re-finance its debt obligations will depend upon the Corporation's financial and operating performance, which in turn will partially depend upon prevailing industry and general economic conditions which are beyond the Corporation's control. There can be no assurance that the Corporation's operating performance, cash flow and capital resources will be sufficient to service and/or repay its debt in the future, in which case the Corporation may be required to sell assets to repay its debt, defer capital expenditures or raise additional equity, to the extent available.

## **Other Risks Affecting the Corporation's Business**

***Terrorist attacks and the threat of terrorist attacks may have an adverse impact on the energy transportation industry.***

The long-term impact of terrorist attacks in the United States, such as the attacks on September 11, 2001, and in Canada and the threat of future terrorist attacks on the energy transportation industry in general, and on the Corporation in particular, is not known at this time. The possibility that infrastructure facilities may be direct targets of, or indirect casualties of, an act of terror and the implementation of security measures which may be taken as a precaution against possible terrorist attacks will result in increased costs to the Corporation's business.

***There are potential conflicts of interest to which some of the Corporation's directors and officers will be subject in connection with the Corporation's operations.***

Some of the Corporation's directors and officers are engaged and will continue to be engaged in the search of oil and gas interests on their own behalf and on behalf of other corporations, and situations may arise where the directors and officers will be in direct competition with the Corporation. From time to time, the Corporation may jointly participate in exploration and development activities with one or more corporations with which a director or officer of the Corporation may be involved. Additionally, the President and Chief Executive Officer of the

Corporation is also an officer and director of Petrolifera and two of the Corporation's other directors are directors of Petrolifera. These individuals receive compensation from Petrolifera for their services. Conflicts of interest, if any, which arise will be subject to and be governed by procedures prescribed by the *Business Corporations Act* (Alberta) which require a director or officer of a corporation who is a party to or is a director or an officer of or has a material interest in any person who is a party to a material contract or proposed material contract with the Corporation to disclose his interest and to refrain from voting on any matter in respect of such contract unless otherwise permitted under the *Business Corporations Act* (Alberta).

#### **LEGAL PROCEEDINGS**

There are no material legal proceedings against the Corporation.

#### **INTERESTS OF EXPERTS**

Each of Sayer and GLJ have prepared a report or valuation described herein. Neither Sayer or GLJ held any interests in securities or other property of Connacher when it prepared its respective report or valuation, has received any such interest since such time or will receive any such interest. No director, officer or employee of Sayer or GLJ is to be elected, appointed or employed by Connacher.

#### **ADDITIONAL INFORMATION**

Additional information, including information as to directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans, if applicable, is contained in the Management Information Circular of the Corporation prepared in connection with the most recent annual meeting of shareholders of the Corporation that involved the election of directors. Additional financial information is provided in the Corporation's financial statements and management discussion and analysis for the year ended December 31, 2007, which are contained in the Annual Report of the Corporation for the year ended December 31, 2007.

Copies of this Annual Information Form, the Corporation's Annual Report, any interim financial statements of the Corporation subsequent to those statements contained in the Annual Report, the Corporation's Management Information Circular and other additional information relating to the Corporation are available on SEDAR at [www.sedar.com](http://www.sedar.com).

**SCHEDULE A  
REPORT ON RESERVES DATA BY  
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR**

To the board of directors of Connacher Oil and Gas Limited (the "**Company**"):

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2007. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs.
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, 2007, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors.

<b>Independent Qualified Reserves Evaluator</b>	<b>Description and Preparation Date of Evaluation Report</b>	<b>Location of Reserves (Country or Foreign Geographic Area)</b>	<b>Net Present Value of Future Net Revenue (before income taxes, 10% discount rate -\$M)</b>			
			<u>Audited</u>	<u>Evaluated</u>	<u>Reviewed</u>	<u>Total</u>
			GLJ Petroleum Consultants	February 20, 2008	Canada	-

5. In our opinion, the reserves data 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 our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.
7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 28, 2008.

(Signed) "*Dana B. Laustsen*"  
**Dana B. Laustsen, P.Eng.**  
**Executive Vice-President**

**REPORT ON RESOURCES DATA  
BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR**

To the board of directors of Connacher Oil and Gas Limited (the "Company"):

1. We have prepared an evaluation of the Company's resources data as at December 31, 2007. The resources data are estimates of low, best and high estimates of contingent and prospective resources and related future net revenue as at December 31, 2007, estimated using forecast prices and costs.
2. The resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the resources 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 resources data are free of material misstatement. An evaluation also includes assessing whether the resources data are in accordance with principles and definitions in the COGE Handbook.
4. The following table sets forth the estimated future net revenue of the Company (before deduction of income taxes) attributed to best estimate contingent resources and best estimate prospective resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, evaluated by us for the year ended December 31, 2007, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator and Resource Category	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)			
			<u>Audited</u>	<u>Evaluated</u>	<u>Reviewed</u>	<u>Total</u>
<b><u>Contingent Resources</u></b>	February 20, 2008	Canada	-	\$348,108	-	\$348,108
GLJ Petroleum Consultants						
<b><u>Prospective Resources</u></b>	February 20, 2008	Canada	-	\$379,308	-	\$379,308
GLJ Petroleum Consultants						

5. In our opinion, the resources 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 our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.
7. Because the resources data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that resources are categorized according to the probability of their recovery.
8. Contingent resources evaluated in this report were assigned in regions with lower core hole drilling density than the reserve regions and are outside current areas of application for development. These resource estimates are not classified as reserves at this time, pending further reservoir delineation, project application, facility and reservoir design work. Contingent resources entail commercial risk not applicable to reserves, which have not been included in the net present valuation. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

9. Prospective resources were assigned in unexplored regions of the Company's acreage. Prospective resources entail commercial risk not applicable to reserves and contingent resources, which have not been included in the net present valuation. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources.

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 29, 2008.

(Signed) "*Dana B. Laustsen*"  
***Dana B. Laustsen, P.Eng.***  
***Executive Vice-President***

**SCHEDULE B**  
**REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE**

Management of Connacher Oil and Gas Limited (the "**Corporation**") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator is presented in Schedule A and will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Corporation has

- (a) reviewed the Corporation'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 Reserves Committee of the board of directors has reviewed the Corporation'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, on the recommendation of the Reserves Committee, approved

- (a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
- (b) the filing of Form 51-101F2 which is 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 judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) *Richard A. Gusella*  
Richard A. Gusella  
President and Chief Executive Officer

(signed) *W.C. (Mike) Seth*  
W.C. (Mike) Seth  
Director

(signed) *Richard R. Kines*  
Richard R. Kines  
Vice President Finance and Chief Financial Officer

(signed) *D. Hugh Bessell*  
D. Hugh Bessell  
Director

March 20, 2008

**SCHEDULE C**  
**CONNACHER'S 26 PERCENT INTEREST IN PETROLIFERA'S OIL AND GAS RESERVES**  
**AND FUTURE NET REVENUE**

The following is a summary of the Corporation's 26 percent interest in Petrolifera's oil and gas reserves and future net revenue as at December 31, 2007 as evaluated by GLJ in the Petrolifera GLJ Report. The information contained within this Schedule C has been derived from the Petrolifera AIF which is posted on SEDAR ([www.sedar.com](http://www.sedar.com)).

**OIL AND GAS RESERVES BASED ON**  
**FORECAST PRICES AND COSTS - DECEMBER 31, 2007<sup>(9)</sup>**

	Light/Medium Crude Oil		Natural Gas		Natural Gas Liquids	
	Gross <sup>(1)</sup> (mbl)	Net <sup>(1)</sup> (mbl)	Gross <sup>(1)</sup> (mmcf)	Net <sup>(1)</sup> (mmcf)	Gross <sup>(1)</sup> (mbl)	Net <sup>(1)</sup> (mbl)
Proved Developed Producing <sup>(2)(7)</sup>	2,181	1,887	1,685	1,457	35	30
Proved Developed Non-Producing <sup>(2)(6)</sup>	93	80	635	550	13	11
Proved Undeveloped <sup>(2)(8)</sup>	1,557	1,347	1,913	1,655	40	34
Total Proved <sup>(2)</sup>	3,831	3,313	4,233	3,662	87	75
Probable <sup>(3)</sup>	1,635	1,414	2,078	1,797	43	37
Total Proved Plus Probable <sup>(2)(3)</sup>	5,465	4,727	6,311	5,459	130	113
Total Possible <sup>(4)</sup>	3,055	2,643	2,389	2,066	49	43
Total Proved Plus Probable Plus Possible <sup>(2)(3)(4)</sup>	8,520	7,370	8,700	7,525	179	155

**NET PRESENT VALUES OF FUTURE NET REVENUE BASED ON**  
**FORECAST PRICES AND COSTS - DECEMBER 31, 2007<sup>(9)</sup>**

(M\$)	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes Discounted At					Unit Value Before Income Tax Discounted at 10%/year	
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%	(\$/boe)	(\$/mcf)
	Proved Developed Producing <sup>(2)(7)</sup>	62,311	53,806	47,432	42,506	38,601	47,970	41,325	36,366	32,547	29,528	21.96
Proved Developed Non-Producing <sup>(2)(6)</sup>	3,664	2,906	2,410	2,062	1,807	2,402	1,842	1,487	1,246	1,073	13.16	2.19
Proved Undeveloped <sup>(2)(8)</sup>	52,665	40,129	31,870	26,111	21,910	35,060	26,334	20,615	16,645	13,761	19.24	3.21
Total Proved <sup>(2)</sup>	118,640	96,841	81,711	70,680	62,318	85,432	69,501	58,468	50,439	44,362	20.43	3.41
Probable <sup>(3)</sup>	53,513	43,310	35,823	30,212	25,914	34,748	28,136	23,267	19,616	16,820	20.46	3.41
Total Proved Plus Probable <sup>(2)(3)</sup>	172,153	140,151	117,534	100,891	88,232	120,180	97,637	81,735	70,055	61,183	20.44	3.41
Total Possible <sup>(4)</sup>	95,926	69,380	52,947	41,963	34,217	62,393	44,299	33,308	26,076	21,045	15.12	2.52
Total Proved Plus Probable Plus Possible <sup>(2)(3)(4)</sup>	268,079	209,532	170,480	142,854	122,449	182,573	141,936	115,043	96,131	82,228	19.42	3.24

**TOTAL FUTURE NET REVENUE (UNDISCOUNTED)**  
**BASED ON FORECAST PRICES AND COSTS - DECEMBER 31, 2007<sup>(9)</sup>**

(M\$)	Revenue	Royalties	Operating Expenses	Capital Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Total Proved <sup>(2)</sup>	190,057	25,658	40,360	4,836	562	118,640	33,209	85,432
Total Proved Plus Probable <sup>(2)(3)</sup>	272,221	36,750	53,661	8,941	715	172,153	51,973	120,180
Total Proved Plus Probable Plus Possible <sup>(2)(3)(4)</sup>	428,632	57,865	82,791	18,966	930	268,079	85,506	182,573

**Notes:**

- (1) "Gross Reserves" are the Corporation's working interest (operating or non-operating) share before deducting royalties and without including any royalty interests of the Corporation. "Net Reserves" are the Corporation's working interest (operating or non-operating) share after deduction of royalty obligations plus the reporting issuer's royalty interests in reserves.

- (2) "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.
- (3) "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) "Possible" reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.
- (5) "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 (e.g. when compared to the cost of drilling a well) to put the reserves on production.
- (6) "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.
- (7) "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 certainty.
- (8) "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 category (proved, probable, possible) to which they are assigned.
- (9) The pricing assumptions used in the Petrolifera GLJ Report with respect to the inflation rates used for operating and capital costs and exchange rates are set forth below and are as at December 31, 2007.

	<b>Inflation Rate</b>	<b>Exchange Rate</b>
	%/year	\$US/\$Cdn
Year Forecast		
2008	0%	1:1
2009	2%	1:1
2010	2%	1:1
2011	2%	1:1
2012	2%	1:1
2013	2%	1:1
2014	2%	1:1
2015	2%	1:1
2016	2%	1:1
2017	2%	1:1
2018	2%	1:1
Thereafter	2%	1:1

The crude oil price received by Petrolifera is dependent on the price level of WTI. If WTI is greater than US\$60.90/bbl, the maximum price for the Corporation's crude oil is US\$42.00/bbl. If WTI is between US\$45.00/bbl and US\$60.00/bbl, there is a 31% withholding tax on the crude oil price. Prices are not defined for levels of WTI below US\$45.00. Crude oil prices are assumed to escalate at 2% per year thereafter.

Forecast prices used in the above formula are as follows:

	<b>Light and Medium Crude Oil</b>
	<b>Argentina Crude Oil Price (\$Cdn/bbl)</b>
Year Forecast	
2008	42.00
2009	42.84
2010	43.70
2011	44.57
2012	45.46
2013	46.37
2014	47.30
2015	48.24
2016	49.21
Thereafter	Plus 2%

The forecast price assumptions relating to natural gas are as follows:

	<b>Natural Gas</b>
	<b>Argentina Gas Price</b>
	<b>(\$Cdn/mmbtu)</b>
Year Forecast	
2008	2.10
2009	2.14
2010	2.18
2011	2.23
2012	2.27
2013	2.32
2014	2.36
2015	2.41
2016	2.46
Thereafter	Plus 2%

GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

The following table summarizes Connacher's share of the capital expenditures made by Petrolifera on oil and natural gas properties for the year ended December 31, 2007:

	<b>Property Acquisition Costs</b>		<b>Exploration Costs</b>	<b>Development Costs</b>
	<b>Proved Properties</b>	<b>Unproved Properties</b>	<b>(\$)</b>	<b>(\$)</b>
	<b>(\$'000s)</b>	<b>(\$'000s)</b>		
Argentina	-	90	1,014	24,237
Peru	-	-	3,362	-
Colombia	-	-	154	-

**SCHEDULE D**  
**AUDIT COMMITTEE CHARTER**

The Audit Committee (the "**Committee**") of the board of directors (the "**Board**") of Connacher Oil and Gas Limited (the "**Corporation**") shall have the oversight responsibility, authority and specific duties as described below.

**Composition**

The Committee will be comprised of three or more directors as determined by the Board. Each Committee member shall satisfy the independence, financial literacy and experience requirements of applicable securities laws, rules or guidelines, any applicable stock exchange requirements or guidelines and any other applicable regulatory rules. In particular, each member of the Committee shall have no direct or indirect material relationship with the Corporation which could reasonably be expected to materially interfere with the member's independent judgment. Determinations as to whether a particular Director satisfies the requirements for membership on the Committee shall be made by the full Board and shall be reviewed at least annually.

Members of the Committee shall be appointed from time to time by the Board. Each member shall serve until his successor is appointed, unless he shall resign or be removed by the Board or he shall otherwise cease to be a director of the Corporation. If a member of the Committee ceases to be independent for reasons outside that member's reasonable control, the member shall immediately notify the Chair of the Board as to this fact and shall resign his or her position as a member of the Committee on the earliest of (i) the appointment of his or her successor; (ii) the next annual meeting of shareholders of the Corporation; and (iii) the date that is six months from the occurrence of the event which caused the member to not be independent. The Board shall fill any vacancy if the membership of the Committee is less than three Directors.

The Chair of the Committee may be designated by the Board or, if it does not do so, the members of the Committee may elect a Chair by vote of a majority of the full Committee membership.

**Operation**

The Committee shall have access to such officers and employees of the Corporation and to the Corporation's independent external auditors, and to such information respecting the Corporation, as it considers to be necessary or advisable in order to perform its duties and responsibilities. The Committee has the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties and to set and pay the compensation for any such counsel and advisors, such engagement to be for the Corporation's sole account and expense.

Meetings of the Committee shall be conducted as follows:

1. The Committee shall meet at least four times annually at such times and at such locations as the Chair of the Committee shall determine, provided that meetings shall be scheduled so as to permit timely review of the quarterly and annual financial statements and reports. The independent auditors or any one member of the Committee may also request a meeting of the Committee.
2. The quorum for meetings shall be a majority of the members of the Committee, present in person or by telephone or by other telecommunication device that permits all persons participating in the meeting to hear each other.
3. The Chair shall, in consultation with management and the external auditors, establish the agenda for the meetings and instruct management to ensure that properly prepared agenda materials are circulated to the Committee with sufficient time for study prior to the meeting.
4. Every question at a Committee meeting shall be decided by a majority of the votes cast.

5. The Chief Executive Officer shall be available to advise the Committee, and may attend meetings at the invitation of the Chair of the Committee. Other management representatives may be invited to attend. The independent external auditors shall be given notice of, and shall be entitled to attend, each meeting of the Committee at the expense of the Corporation. The Chair of the Committee shall hold in camera meetings of the Committee, without management present, at every Committee meeting.
6. A Committee member, or any other person selected by the Committee, shall be appointed at each meeting to act as secretary for the purpose of recording the minutes of each meeting.
7. The Committee may delegate from time to time to any person or committee of persons any of the Committee's responsibilities that lawfully may be delegated.

The Committee provides an avenue for communication, particularly for outside directors, with the independent external auditors and financial and senior management and the Board. The independent external auditors shall have a direct line of communication to the Committee through its Chair. The Committee, through its Chair, may contact directly any employee in the Corporation as it deems necessary, and any employee may bring before the Committee on a confidential basis any matter involving financial practices or transactions.

### **Responsibilities**

The Committee is part of the Board. Its primary function is to assist the Board in fulfilling its oversight responsibilities with respect to: (i) the preparation and disclosure of the financial statements, and accompanying reports, to be provided to shareholders and regulatory bodies; (ii) the system of internal control and management information systems of the Corporation that management has established; and (iii) the external audit process. In addition, the Committee shall assist the Board as requested in fulfilling its oversight responsibilities with respect to (i) financial policies and strategies; (ii) financial risk management practices; and (iii) transactions or circumstances which could materially affect the financial position or results of operations of the Corporation.

The role of the Committee is one of stewardship and oversight. Management is responsible for preparing the financial statements and financial reporting of the Corporation and for maintaining internal control and management information and risk management systems and procedures. The external auditors are responsible for the audit or review of the financial statements and other services they provide.

The Committee should have a clear understanding with the external auditors that the independent auditors must maintain an open and transparent relationship with the Committee and the Board, and that the ultimate accountability of the external auditors is to the shareholders of the Corporation.

The Committee shall provide the Board with a summary of all meetings by way of an oral report delivered by the Chair of the Committee to the Board. All information reviewed and discussed by the Committee at any meeting shall be referred to in the minutes and made available for examination by the Board upon request to the Chair.

### **Specific Duties**

1. Financial Statements and Financial Reporting.

The Committee shall:

- (a) review with management and the external auditors, and recommend to the Board for approval, the annual financial statements of the Corporation, the reports of the external auditors thereon and related financial reporting, including Management's Discussion and Analysis and financial press releases;
- (b) review with management and the external auditors, and recommend to the Board for approval, the interim financial statements of the Corporation and related financial reporting, including Management's Discussion and Analysis and financial press releases;

- (c) review with management and recommend to the Board for approval, any financial statements of the Corporation which have not previously been approved by the Board and which are to be included in a prospectus of the Corporation;
- (d) consider and be satisfied that adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements (other than disclosure referred to in clauses (a) and (b) above), and periodically assess the adequacy of such procedures;
- (e) review with management, the external auditors and, if necessary, legal counsel, any litigation, claim or contingency, including tax assessments, that could have a material effect upon the financial position of the Corporation, and the manner in which these matters may be, or have been, disclosed in the financial statements;
- (f) review the appropriateness of the accounting practices and policies of the Corporation, the use and effect of judgment on accounting measurements, the adequacy of accruals and estimates used by management in preparing financial statements and review any proposed changes in accounting policies and procedures;
- (g) review accounting, tax and financial aspects of the operations of the Corporation as the Committee considers appropriate; and
- (h) include in the annual information form each year, as required, a copy of the Terms of Reference of the Committee and a report to shareholders on the Committee's activities in satisfying its responsibilities during the year in compliance with these terms of reference.

2. Relationship with External Auditors.

The Committee shall:

- (a) consider and make a recommendation to the Board as to the appointment or re appointment of the external auditors, ensuring that such auditors are participants in good standing pursuant to applicable securities laws;
- (b) consider and make a recommendation to the Board as to the compensation of the external auditors;
- (c) review and approve the annual audit plan of the external auditors;
- (d) oversee the work of the external auditors in performing their audit or review services and oversee the resolution of any disagreements between management and the external auditors;
- (e) review and discuss with the external auditors all significant relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the external auditors' independence, including, without limitation, (A) requesting, receiving and reviewing, on a periodic basis, a formal written statement from the external auditors delineating all relationships that may reasonably be thought to bear on the independence of the external auditors with respect to the Corporation, (B) discussing with the external auditors any disclosed relationships or services that the external auditors believe may affect the objectivity and independence of the external auditors, and (C) recommending that the Board take appropriate action in response to the external auditors' report to satisfy itself of the external auditors' independence;
- (f) pre approve all non audit services (where such non audit services are considered to be above the *de minimus* level referred to in applicable law) to be provided to the Corporation (and any subsidiaries thereof) by the external auditors and review fee arrangements for such services (the Committee may delegate to one or more of its members the authority to pre approve non audit

services so long as such pre approval is presented to the full Committee at its first scheduled meeting following such pre approval); and

- (g) review and approve the hiring policies of the Corporation regarding employees and former employees of the present and former external auditors of the Corporation.

3. Internal Controls.

The Committee shall:

- (a) review with management and the external auditors, the adequacy and effectiveness of the internal control and management information systems and procedures of the Corporation (with particular attention given to accounting, financial statements and financial reporting matters) and determine whether the Corporation are in compliance with applicable legal and regulatory requirements and with the Corporation's policies;
- (b) review the external auditors' recommendations regarding any matters, including internal control and management information systems and procedures, and management's responses thereto;
- (c) establish procedures for the receipt, retention and treatment of complaints, submissions and concerns regarding accounting, internal controls or auditing matters on an anonymous and confidential basis; and
- (d) review with external auditors any corporate transactions in which Directors or officers of the Corporation have a personal interest.

4. Financial Risk Management.

The Committee shall:

- (a) review with management and the external auditors their assessment of significant financial risks and exposures;
- (b) review and assess the steps that management has taken to mitigate such risks;
- (c) review annually the insurable risks and insurance coverages of the Corporation; and
- (d) report the results of such reviews to the Board for the purpose of assisting the Board in identifying the principal business risks associated with the businesses of the Corporation.