



PRESS RELEASE

March 19, 2009

CONNACHER OIL AND GAS LIMITED REPORTS YEAR END 2008 RESULTS; HIGHER DOWNSTREAM CRUDE OIL COSTS AND HIGHER NON-CASH CHARGES RESULT IN LOSS FOR FOURTH QUARTER AND FULL YEAR; RECORD PRODUCTION, REVENUE AND CASH FLOW ACHIEVED; SIGNIFICANT RESERVES GROWTH RECORDED; STRONG LIQUIDITY MAINTAINED; EXPANSION PLANS ANTICIPATED AT GREAT DIVIDE DURING NEXT SEVERAL YEARS AS PRICES RECOVER; SCHEDULES CONFERENCE CALL FOR 9:00 A.M. MDT MARCH 20, 2009

Calgary, Alberta – Connacher Oil and Gas Limited today released its operating and audited financial results for the year ended December 31, 2008. Connacher made significant progress as a company during 2008. We achieved record production which averaged 8,581 barrels of oil equivalent (“boe”) per day (“boe/d”) for the full year 2008, an increase over full year 2007 of 270 percent and 10,341 boe/d in the fourth quarter 2008, an increase of 363 percent over fourth quarter 2007 results. The company’s proved reserves (“1P”) of crude oil, natural gas, natural gas liquids and bitumen, expressed on a boe basis, more than tripled; proved and probable reserves (2P) more than doubled. Our reserve replacement ratio, which is calculated by dividing reserves added in 2008 (grossed up for 2008 production) by record 2008 production, was 38 times for 1P reserves and over 60 times for 2P reserves. We achieved record revenue and cash flow from operations, before changes in non-cash working capital and other items (“cash flow”) from our integrated operation. We recorded a fourth quarter 2008 and full year loss, primarily arising from higher downstream crude oil costs and increased provisions for non-cash charges, including depletion due to record production levels and also including those associated with foreign exchange losses on translation of our U.S. dollar-denominated debt.

Our year-end liquidity remained strong, with \$224 million of cash and \$198 million of working capital. Perhaps more importantly, we sense recovery in the air.

These year-end 2008 and fourth quarter 2008 results will be the subject of a Conference Call at 9:00 a.m. MDT on March 20, 2009. To listen to or participate in the live conference call please dial either (416) 644-3414 or (800) 733-7560. A replay of the event will be available from Friday, March 20, 2009 at 11:00 a.m. MDT until 21:59 (9:59 p.m.) MDT on Friday, March 27, 2009. To listen to the replay please dial either (416) 640-1917 or Toll Free at (877) 289-8525 and enter the passcode 21294037#.

Key operational achievements of 2008 were as follows:

- We commenced full-scale production at Great Divide Pod One (“Pod One”), our first 10,000 bbl/d steam assisted gravity drainage (“SAGD”) oil sands project. Commerciality was declared on March 1, 2008, only two months after production commenced in December 2007; all 15 SAGD well pairs are now onstream.
- We experienced a solid ramp up of bitumen production at Pod One, reaching a peak of 9,870 bbl/d in September 2008, against a rated capacity of 10,000 bbl/d.
- We lowered Pod One steam-to-oil-ratios (SOR’s) to less than three times for the project with instantaneous SOR’s for better wells in the low twos.
- We produced over 3.1 million boe in 2008, including over 2.1 million barrels of bitumen from Pod One. Daily production increased 270 percent to 8,581 boe/d, with a fourth quarter 2008 average rate of 10,341 boe/d.
- Our conventional oil and natural gas production rate averaged over 3,100 boe/d in 2008, an increase of 35% over 2007.
- We secured approval of Algar, our second 10,000 bbl/d SAGD oil sands project, completed and paid for many long-lead equipment items and completed civil work in early 2009.

- We significantly expanded our conventional oil, natural gas and bitumen reserve base through successful drilling programs and the impact of the Algar approval, which moved probable reserves to proved reserves.
- At our refinery in Great Falls, Montana, during 2008 we substantially completed the ultra low sulphur diesel project, on time and on budget.

Summary financial and operating highlights were as follows:

Financial Highlights

	2008	2007	% Change
FINANCIAL			
(\$000 except per share amounts)			
Revenues, net of royalties	629,339	344,520	83
Cash flow (1)	54,817	44,965	22
Basic, per share (1)	0.26	0.22	18
Diluted, per share (1)	0.26	0.22	18
Net earnings (loss)	(26,603)	40,961	(165)
Basic and diluted, per share	(0.13)	0.20	(165)
Property and equipment additions	351,736	322,962	9
Cash on hand, end of period	223,663	392,271	(43)
Working capital, end of period	197,914	389,789	(49)
Term debt, end of period	778,732	664,462	17
Shareholders' equity, end of period	469,087	480,439	(2)
Total assets, end of period	1,431,675	1,258,828	14
COMMON SHARE INFORMATION			
Shares outstanding, end of period (000)	211,182	209,971	1
Weighted average shares outstanding			
Basic (000)	210,794	200,092	5
Diluted (000)	214,647	202,766	6
Common shares traded during the year (000)	393,365	239,590	64
Common share price (\$)			
High	5.26	4.43	19
Low	0.60	3.07	(80)
Close, end of year	0.74	3.79	(80)

(1) Cash flow and cash flow per share do not have standardized meanings prescribed by Canadian generally accepted accounting principles ("GAAP") and therefore may not be comparable to similar measures used by other companies. Cash flow is calculated before changes in non-cash working capital, pension funding and site restoration expenditures. The most comparable measure calculated in accordance with GAAP would be net earnings. Cash flow is reconciled with net earnings on the Consolidated Statement of Cash Flows and in the accompanying Management's Discussion & Analysis ("MD&A"). Commonly used in the oil and gas industry, management uses these non-GAAP measurements for its own performance measures and to provide its shareholders and investors with a measurement of the company's efficiency and its ability to internally fund future growth expenditures.

(2) No dividends have been declared by the company since its incorporation.

(3) The recognition of bitumen sales from the company's first oil sands project, Great Divide Pod One, commenced March 1, 2008, when it was declared "commercial". Prior thereto, no production was reported and all operating costs, net of revenues were capitalized. The 2008 daily production average is based on a full calendar year.

(4) All references to barrels of oil equivalent (boe) are calculated on the basis of 6 Mcf : 1 bbl. This conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Boes may be misleading, particularly if used in isolation.

(5) Netback is a non-GAAP measure used by management as a measure of operating efficiency and profitability. It is calculated as petroleum and natural gas revenue less royalties and operating costs. The most comparable measure calculated in accordance with GAAP would be net earnings. Netback is reconciled with net earnings in the accompanying MD&A.

(6) The reserve and resource estimates for 2008 and 2007 were prepared by GLJ Petroleum Consultants Ltd ("GLJ"), an independent professional petroleum engineering firm, in accordance with Canadian Securities Administrators' National Instrument 51-101 (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook. Under NI 51-101, proved reserves are those reserves which can be estimated with a high degree of certainty to be recoverable. It is 90 percent likely that actual remaining quantities will exceed 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 proved plus probable reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

Operating Highlights

	2008	2007	% Change
OPERATING			
Production			
Bitumen (bbl/d) (3)	5,456	-	-
Crude oil (bbl/d)	1,029	792	30
Natural Gas (mcf/d)	12,570	9,172	37
Equivalent (boe/d) (4)	8,581	2,320	270
Pricing			
Bitumen (\$/bbl)	45.74	-	-
Crude oil (\$/bbl)	82.01	52.80	55
Natural gas (\$/mcf)	7.90	6.38	24
Selected highlights (\$/boe) (4)			
Weighted average sales price	50.49	43.22	17
Royalties	5.00	6.93	(28)
Operating and transportation costs	20.38	11.06	84
Operating Netback (5)	25.11	25.23	-
RESERVES AND RESOURCES			
Reserves volumes (mboe) (6, 7)			
Proved (1P) reserves	182,840	59,857	205
Proved plus probable (2P) reserves	379,476	187,250	103
Proved plus probable plus possible (3P) reserves	452,295	251,468	80
Reserves values (\$million) (8)			
1P reserves	1,026	603	70
2P reserves	1,543	1,194	29
3P reserves	2,274	1,308	74
REFINERY			
Refining throughput			
Crude charged (bbl/d)	9,184	9,485	(3)
Refinery utilization (%)	97	100	(3)
Margins (%)	(2.0)	15.4	(113)

Notes (1) to (6) on previous page

(7) After production of 3.1 million boe in 2008.

(8) 10 percent present value of future net revenue before taxes.

(9) Possible reserves account for 73 mmboe of the estimated total 3P reserves.

There is only a 10 percent probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

Year in Review

Connacher had an excellent year of execution and achievement in 2008, reporting record production, revenue and cash flow. Events near year end, including the meltdown of commodity, stock and credit markets impacted adversely on our fourth quarter 2008 and thus on our full year 2008 financial and operating results. Nevertheless, we view our operational accomplishments for the year as considerable.

The collapse of crude oil prices and economic downturn occurred quickly and on a global basis. As a producer of bitumen in Alberta's oil sands, we reacted quickly to weaker crude oil prices, widened heavy oil differentials and challenging operating costs by curtailing production at Pod One in December 2008. Subsequently, within about one month of this curtailment, we were able to restore our operations to full capacity due to steps we took to capitalize on contango in the crude oil price and on other factors which improve our selling price at Pod One. Accordingly, we are now in the midst of ramping volumes up to pre-shutdown levels, which were approaching 10,000 bbl/d. At those production levels, our steam/oil ratios ("SOR's") were favorable, at around three times overall and approaching two times at some of our better wells, before the curtailment. We anticipate again achieving these metrics in 2009.

We have since drilled two new SAGD well pairs in proximity to our best well at Pod One and following completion, tie-in and steaming, will place these wells onstream around mid-year 2009. We also intend to install four of nine electrical submersible pumps we have in inventory during the next several months. This should contribute to improvements in both reliability and productivity with lower SOR's from the wells into which this artificial lift will be installed. This is in keeping with our emphasis on production optimization and cost control in a lower crude oil price environment.

Our current production at Pod One is approximately 8,000 bbl/d. We are ramping up at a measured pace towards 10,000 bbl/d to ensure our cost control goals can be achieved. Our facility operated well throughout 2008 and we overcame minor operational challenges throughout the year. We have recently been successful in reducing operating costs, assisted by higher production volumes. We are targeting to have our operating costs at Pod One in the \$17-\$20 bbl range for full year 2009, depending on the cost of natural gas, which we believe would make Connacher among the lowest if not the lowest cost operator in the oil sands at this time.

Consistent with our commitment to an integrated strategy comprised of repeatability, long-term sustainability and expandability of our production base in the oil sands, we applied for regulatory approval to construct our second 10,000 SAGD project at Algar in the latter half of 2007. In November 2008, we received the requisite approvals for this project and immediately commenced civil work on the access road, plant site and three well pads. We had previously ordered numerous long-lead equipment items to maintain our execution record for timely project completion. Market conditions deteriorated to such an extent that in mid-December, we decided to suspend construction of Algar, once we completed the civil work on the access road, plant site and three well pads. To date, we have invested approximately \$150 million in Algar, the total cost of which had been financed in late 2007 and was estimated at \$345 million, excluding approximately \$14 million related to the decision to suspend construction. We appreciate this is a long term investment, but liquidity remains the priority for most oil companies at this time. We will reinstate construction, plant assembly and drilling of the proposed 15 SAGD well pairs for Algar at the earliest opportune time, upon indication of improved capital markets and with satisfactory evidence of a sustainable recovery in crude oil prices, thus providing a reasonable prospect of an adequate rate of return on our investment.

Our 9,500 bbl/d heavy oil refinery, located in Great Falls, Montana made respectable progress through a challenging economic period in 2008. Profitability was adversely impacted by the rapid escalation in crude oil prices that occurred in the first half of 2008, coupled with the inability of the refinery to pass on its higher input costs in the prices received for its refined products, especially asphalt. A deteriorating U.S. economy put downward pressure on gasoline prices in the latter part of 2008, which also negatively impacted the refinery's results for the year. The refinery was able to offset these poor conditions somewhat by expanding its middle distillate and asphalt product markets. We also capitalized on our small refiner niche to secure an important U.S. government jet fuel contract. The refinery has substantially completed construction of its ultralow sulphur diesel ("ULSD") project, on time and on budget. The refinery did experience some throughput reduction in December 2008 and during the first quarter 2009, associated with the tie-in of the ULSD facility and also because of extreme cold weather. Regardless, we have commenced the production of ULSD in March 2009.

In the first quarter of 2009, we continued a modest exploration program at Great Divide, with a total of 24 core holes being drilled. We are pleased with the overall results of this program, which enhances our overall understanding of the reserve potential of our main lease block.

On March 9, 2009 we submitted a Terms of Reference for a proposal to expand our Great Divide Pod One and Algar SAGD facilities (“Great Divide SAGD Expansion Project”) from a current authorized level of 20,000 bbl/d of bitumen to approximately 44,000 bbl/d of bitumen. The Terms of Reference is the first step in the process of preparing an Environmental Impact Assessment (“EIA”) for the Great Divide SAGD Expansion Project, as directed by Alberta Environment.

Fourth Quarter 2008 and Full Year 2008

The fourth quarter 2008 was a difficult period for Connacher. Revenues fell from the prior quarter and we experienced modest negative cash flow, primarily due to the dramatic drop in crude oil prices and the widening of heavy crude oil price differentials, which particularly affected bitumen producers. This detracted from our record performance during the first three quarters of 2008. Additionally, the fourth quarter of any year is normally the period when we start to build our asphalt inventories at our refinery. As a result of lower crude oil prices and refined product pricing, we recorded a downward valuation adjustment of \$9 million in this reporting period, for all refined products we carry in inventory, including our expanding asphalt inventory. We charged this amount as an expense in our Statement of Operations. As a result, our refining division reported an operating loss for the period. These adverse factors were offset by a provision for a significant cash tax recovery, for both the fourth quarter 2008 and for the full year reporting period. This more than offset the inventory valuation adjustment and resulted in positive after-tax operating income in both reporting periods for our refining division.

For the fourth quarter 2008, upstream production was 10,341 boe/d compared to 2,233 boe/d in the fourth quarter of 2007, an increase of 363 percent. This was achieved despite the short-term curtailment of bitumen production at Pod One in mid-December 2008. Revenue was \$102 million compared to \$225 million in the third quarter of 2008 and \$83 million in the fourth quarter of 2007, reflecting crude oil price volatility. Our cash flow deficiency was \$4.7 million in the fourth quarter of 2008. Please refer to the MD&A below for reconciliation of cash flow to net loss. A loss of \$43.6 million was recorded, primarily due to non-cash charges. These included an increased provision for depletion due to higher upstream production, a provision for a foreign exchange loss on the translation of our U.S. dollar denominated debt, higher future taxes and the write-off of certain costs, including those related to the original arrangement of the company’s terminated credit facilities and for front end engineering and design studies related to the deferral of refinery expansion plans.

For the full year 2008, cash flow was a record \$55 million, an increase of 22 percent compared to \$45 million in 2007. On a weighted average outstanding basis of 211 million shares in 2008 (200 million in 2007), cash flow per share was \$0.26 compared to \$0.22 in 2007. Please refer to the MD&A below for reconciliation of cash flow to net loss.

A net loss of \$26.6 million (\$0.13 per share) was recorded in fiscal 2008, after a provision for non-cash charges totaling \$80 million, compared to net earnings in 2007 of \$41 million (\$0.20 per share). Connacher ended the year with \$224 million of cash, working capital of \$198 million and \$779 million of long term debt. None of the company’s debt is repayable until 2012 and most of it is not repayable until 2015. A significant portion (\$89 million) of the company’s year end cash balances was derived from the successful monetization of the currency and interest rate swaps associated with the company’s outstanding U.S. dollar-denominated Second Lien Note issue. This significant contribution to corporate liquidity was achieved without share dilution or the incurrence of additional indebtedness.

Subsequent to year end 2008, Connacher elected to cancel its undrawn \$150 million and US\$50 million credit facilities. We had attempted to renegotiate certain key terms of the facilities, but we were unsuccessful in securing acceptable revisions from our banking syndicate. In order to further enhance our financial flexibility and liquidity, as we now have considerable unused credit capacity following the cancellation of our former facilities, we are investigating alternative credit sources. We have already arranged a cash-collateralized letter of credit facility in the amount of \$20 million to facilitate our normal business transactions requiring letters of credit. New funding would supplement our strong year end 2008 cash balances and working capital. We also intend to examine other opportunities to restructure components of our balance sheet, in the context of lower commodity prices.

While we sense recovery, we also expect the early part of 2009 will be challenging. We have already experienced difficult conditions during the first few months of 2009, although we are currently experiencing improved market conditions. Nevertheless, in response to these circumstances, we have curtailed our anticipated capital spending for 2009 to approximately \$123 million, down from previous levels approximating \$373 million. Most of these expenditures will occur in the first quarter 2009, primarily related to Algar. Details of our continuing program are provided in greater detail herein.

We anticipate a much improved full year contribution from our refining operations, primarily due to healthy asphalt markets. Newly-announced U.S. government infrastructure projects are anticipated to result in an unprecedented demand for asphalt. This product is currently in short supply in the United States. This improvement should start to be apparent in the second quarter of 2009. We also anticipate positive net operating income from our upstream operations. With our significant cash balances and our operating cash flow, we anticipate being able to fund all of our capital spending activities and meet all financial obligations throughout 2009, even if crude oil prices stay at WTI US\$45.00/bbl for the balance of this year, without having to raise any additional capital.

We continue to believe preserving our liquidity and protecting our assets are the priority responsibilities for 2009. We have ample identified reserves and resources to remain confident of our long-term growth prospects and we believe energy prices will improve as the year unfolds. To stabilize our outlook in a volatile period and protect against the possibility of renewed crude oil price weakness, we have arranged WTI hedges at prices of US\$46.00/bbl and US\$49.50/bbl, on approximately one half of our anticipated bitumen production for much of 2009. We have a built-in physical hedge with our own natural gas production at Marten Creek, Randall, Latornell, Seal and other areas. We believe that this minimizes the impact of volatility in natural gas prices on our overall operations.

Revised Capital Budget

In view of changed capital market conditions, we have elected to preserve liquidity and reduce our 2009 capital expenditures to \$123 million as follows:

(\$million)	New	Original
Upstream		
Conventional	\$13	\$15
Pod One	18	20
Algar	29	208
Algar capitalized items	30	69
Cogeneration	4	22
Exploration	9	10
EIA and other	3	3
Downstream		
Refining	17	26
Total	\$123	\$373

Connacher Oil and Gas Limited is a Calgary based crude oil, natural gas and bitumen producer. Our principal asset is our interest in the Great Divide oil sands project in northeastern Alberta. We also own a 9,500 bbl/d heavy oil refinery in Great Falls, Montana and a 24 percent equity stake in Petrolifera Petroleum Limited, a public company listed for trading on the Toronto Stock Exchange, with assets in South America.

Forward Looking Information

This press release contains forward-looking information including estimations of reserves and resources and future net revenue associated therewith, expectations of future production and SORs at Pod One, timing for two new SAGD wells to commence production, planned installation of electrical submersible pumps, anticipated improvements in reliability and productivity of SAGD wells with artificial lift installed, anticipated reductions in operating costs, timing and future considerations for reactivation of construction of Algar, timing for initiating ULSD production, future expansion plans at Great Divide, anticipated capital spending for 2009 and sources of funding thereof, anticipated improvement in financial results of the refining operation and anticipated improvements in commodity prices, investigation of financing alternatives to restructure balance sheet components and efforts to secure new, acceptable sources of credit to replace facilities cancelled by the company. Forward looking information is based on

management's expectations regarding future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), plans for and results of drilling activity, environmental matters, business prospects and opportunities. Forward-looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated. These risks include, but are not limited to: the risks associated with the oil and gas industry (e.g., operational risks in development, exploration, and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve and resource estimates; the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety, and environmental risks), and the risks of commodity price and foreign exchange rate fluctuation, and risk and uncertainties associated with maintaining necessary regulatory approvals. In addition, the current financial crisis has resulted in severe economic uncertainty and resulting illiquidity in credit and capital markets which increases the risk that actual results will vary from forward looking expectations in this press release and these variations may be material. In particular, there can be no assurance that the company will be able to secure new sources of credit on terms and conditions acceptable to the company or at all or that the company will be successful in its efforts to restructure certain components of its balance sheet. These risk and uncertainties are described in details in Connacher's Annual Information Form for the year ended December 31, 2008, which is available at www.sedar.com.

Information relating to "reserves" and "resources" and "future net revenues" associated therewith are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources, as the case may be, described exist in the quantities predicted or estimated, and can be profitably produced in the future to achieve the future net revenue calculated in accordance with certain assumptions. The assumptions relating to the reserves and resources of the Corporation and associated future net revenues are contained in the 2008 GLJ Report and are summarized in Connacher's Annual Information Form for the year ended December 31, 2008. Future net revenues associated with reserves and resources do not necessarily represent fair market value. Connacher assumes no obligation to update or revise the forward-looking information to reflect new events or circumstances, except as required by law.

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Management Discussion and Analysis

The company's long-term business plan anticipates continued substantial growth. Emphasis will be on developing the Great Divide Oil Sands Project in Alberta, while continuing to develop the company's recently-expanded conventional production base and operating the Montana refinery.

The following is dated as of March 19, 2009 and should be read in conjunction with the consolidated financial statements of Connacher Oil and Gas Limited ("Connacher" or the "company") for the years ended December 31, 2008 and 2007 as contained in this annual report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and are presented in Canadian dollars. This MD&A provides management's view of the financial condition of the company and the results of its operations for the reporting periods.

Forward-looking Information

This report, including the Letter to Shareholders, contains forward-looking information including but not limited to estimations of reserves and resources and future net revenue associated therewith, expectations of future production, net operating income, cash flow, profitability and capital expenditures, anticipated reductions in operating costs as a result of optimization of certain operations, development of additional oil sands resources (including Algar and the timeline and capital costs for construction of Algar), expansion of current conventional oil and gas and oil sands operations, and timely expansion or downstream refining and marketing opportunities, initiation of ultra low sulphur diesel production, planned construction of a cogeneration facility and anticipated sources of funding for capital expenditures and plans for improving liquidity which may include securing a new credit facility, accessing new equity, corporate acquisitions or business combinations, joint venture arrangements and restructuring components of the balance sheet. Forward looking information is based on management's expectations regarding future growth, results of operations, production, future commodity prices and foreign exchange rates, future capital and other expenditures (including the amount, nature and sources of funding thereof), plans for and results of drilling activity, environmental matters, business prospects and opportunities and future economic conditions. Forward-looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated. These risks include, but are not limited to: the risks associated with the oil and gas industry (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve and resource estimates; the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks), the risk of commodity price and foreign exchange rate fluctuations, risks associated with the impact of general economic conditions, risks and uncertainties associated with securing and maintaining the necessary regulatory approvals and financing to proceed with the continued expansion of the Great Divide Oil Sands Project. In addition, the current financial crisis has resulted in severe economic uncertainty and resulting illiquidity in credit and capital markets which increases the risk that actual results will vary from forward looking expectations in this report and these variations may be material. These and other risks and uncertainties are described in further detail in Connacher's Annual Information Form for the year ended December 31, 2008, which is available at www.sedar.com. Information relating to "reserves", "resources" and "future net revenues" associated therewith are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future to achieve the future net revenue calculated in accordance with certain assumptions. The assumptions relating to the reserves and resources and associated future net revenues reported herein are contained in the GLJ 2008 Report and are summarized in Connacher's Annual Information Form for the year ended December 31, 2008. Future net revenues associated with reserves and resources do not necessarily represent fair market value. Additionally, certain information relating to Petrolifera's future exploration and development plans, capital expenditures and proposed sale of its Argentinean oil and gas interests represent forward-looking information that has been publicly released by Petrolifera. This information is subject to change in the discretion of the Board of Directors of Petrolifera. Although Connacher believes that the expectations in such forward-looking information are reasonable, there can be no assurance that such expectations shall prove to be correct. The forward-looking information included in this report are expressly qualified in their entirety by this cautionary statement, The forward-looking information included in this report is made as of

March 19, 2009 and Connacher assumes no obligation to update or revise any forward-looking information to reflect new events or circumstances, except as required by law.

Throughout the MD&A, per barrel of oil equivalent (boe) amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil (6:1). The conversion is based on an energy equivalency conversion method primarily applicable to the burner tip and does not represent a value equivalency at the wellhead. Boes may be misleading, particularly if used in isolation.

Business Strategy and Report Card

Strategic Priorities	Progress through 2008
Own and operate large focused working interests	Retained 100 percent working in Great Divide Oil Sands Project. Maintained very high working interests in our conventional crude oil and natural gas assets. Own and operated the Montana Refinery.
Focus on projects with characteristics of expandability, repeatability and sustainability	Commenced commercial production at our first 10,000 bbl/d oil sands project (Pod One) Initiated construction of next phase, Algar. Expanded conventional natural gas production, gathering and processing facilities at Randall, Alberta. Tripled proved bitumen reserves and doubled proved and probable bitumen reserves.
Mitigate and manage risks of a smaller company in the oil sands with an integrated approach	Natural gas production exceeded usage at Pod One. Natural hedge provided by Montana refinery allowed the company to capture heavy oil differentials. Modular approach permitted on time facilities construction, cost control and ramp up. Pre-funded capital programs.
Operate with financial discipline	Fully funded Algar in advance of the current financial crisis and prior to commencing construction. Applied discipline to our operations. Planned 2009 optimization programs.

Three Year Summary Information

(\$000 except per share amounts)	2008	2007	2006
Total revenues, net of royalties	\$629,339	\$344,520	\$244,684
Net earnings (loss)	(26,603)	40,961	6,953
Basic and diluted, per share	(0.13)	0.20	0.04
Total assets	1,431,675	1,258,828	712,930
Longterm financial liabilities	778,732	664,462	209,754
Dividends declared/paid	—	—	—

Connacher has experienced substantial growth since 2006. The main driver for the increase in revenue from 2006 to 2007 was the full year of revenue recognized from refinery sales in 2007, compared to nine months' revenue from sales in 2006, since its acquisition in March that year. The revenue increase from 2007 to 2008 was primarily attributed to increased upstream production volumes, resulting from the company's first oil sands project (Pod One) achieving commerciality on March 1, 2008 together with increased conventional crude oil and natural gas production. These factors resulted in a 270 percent increase in year over year average daily production (8,581 boe/d vs. 2,320 boe/d). The company's long-term intentions anticipate continued increases in upstream production and sales volumes through the continued development of additional oil sands and conventional oil and gas projects.

Although changes to commodity prices for its upstream and refining product sales have resulted in year-to-year changes in net earnings the most significant factors causing fluctuations between 2006 and 2008 have been non-cash charges and gains. These include foreign exchange (2006 - \$4 million loss; 2007 - \$27 million gain; 2008 - \$12 million loss) attributable to the fluctuations in the rate of exchange between the Canadian and U.S. dollar in translating the company's U.S. dollar-denominated debt and depletion and depreciation expense, as it increased 81 percent in 2008 (to \$56 million) from lower amounts reported in 2006 (\$33 million) and 2007 (\$31 million). The primary driver for the increase in depletion and depreciation in 2008 was the 270 percent increase in upstream production volumes, as noted above.

The company's earnings will continue to be subject to the volatility of foreign exchange rates upon the translation of its U.S. dollar-denominated debt, which comprises the majority of its long-term debt. Connacher did maintain a currency and interest rate hedge on a portion of this debt, but decided to realize the benefit of a weak Canadian dollar in November 2008 and unwound the hedge for net cash proceeds of \$89 million. Similar hedges may be re-instated in the future under appropriate conditions and circumstances.

Since 2006, total long-term debt has increased, as it has been one source of funding for expanding the company's asset base. The majority of this growth has been in the oil sands, as Pod One was completed in 2007 at a cost of \$272 million and commenced commercial production in early 2008. The company's second 10,000 bbl/d SAGD oil sands project, Algar, was partially constructed at December 31, 2008 with approximately \$150 million of costs incurred to date.

Financial and Operating Review

Upstream Netbacks (\$000)

For the year ended December 31

2008	Oil Sands ⁽¹⁾	Crude Oil	Natural	Total
Gross revenues (2)	\$198,031	\$30,982	\$36,356	\$265,369
Diluent purchased (3)	(92,291)	–	–	(92,291)
Transportation costs	(14,403)	(96)	–	(14,499)
Production revenue	91,337	30,886	36,356	158,579
Royalties	(948)	(7,229)	(7,535)	(15,712)
Operating costs	(52,758)	(4,525)	(6,710)	(63,993)
Operating netback (4)	\$37,631	\$19,132	\$22,111	\$78,874
Operating netback as a percentage of production	41.2	61.9	60.8	49.7

2007			
Gross revenues/production revenue	\$15,257	\$21,332	\$36,589
Royalties	(3,632)	(2,235)	(5,867)
Operating costs	(3,193)	(6,171)	(9,364)
Operating netback ⁽⁴⁾	\$8,432	\$12,926	\$21,358
Operating netback as a percentage of production revenue	55	61	58

(1) In the first quarter of 2008, Connacher completed the conversion of a majority of its fifteen horizontal well pairs to production status at Pod One and processed increasing levels of bitumen through its facility. This provided the company with the necessary confidence that this first oil sands project could economically produce, process and sell bitumen on a continuous basis. Therefore, effective March 1, 2008 Connacher declared it to be "commercial." As a result, the company discontinued the capitalization of all pre-operating costs, moved accumulated capital costs into the full cost pool, commenced the depletion of these costs, and began reporting Pod One production and operating results as part of the oil and gas segment. The above tables, therefore, do not include operating results prior to March 1, 2008.

(2) Bitumen produced at Pod One is mixed with purchased diluent and sold as "dilbit". Diluent is a light hydrocarbon that improves the marketing and transportation quality of bitumen. In the above tables, gross revenues represent sales of dilbit, crude oil and natural gas.

(3) Diluent volumes purchased and blended into dilbit sales have been deducted in calculating netbacks.

(4) Operating netbacks, by product, are calculated by deducting, as applicable, the related diluent, transportation, field operating costs and royalties from revenues. Netbacks on a per-unit basis are calculated by dividing operating netbacks by production volumes. Netbacks do not have a standardized meaning prescribed by GAAP and, therefore, may not be comparable to similar measures used by other companies. This non-GAAP measurement is a useful and widely used supplemental measure of the company's efficiency and its ability to fund future growth through capital expenditures. Netbacks are reconciled to net earnings below.

Upstream Sales and Production Volumes

For the year ended December 31	2008	2007	% Change
Dilbit sales – bbl/d ⁽¹⁾	7,533	–	–
Diluent purchased – bbl/d ⁽¹⁾	(2,077)	–	–
Bitumen produced and sold – bbl/d ⁽¹⁾	5,456	–	–
Crude oil produced and sold – bbl/d	1,029	792	30
Natural gas produced and sold – mcf/d	12,570	9,172	37
Total – boe/d	8,581	2,320	270

(1) Since declaring Pod One "commercial" effective March 1, 2008. Daily averages are based on total calendar days during the year.

Upstream Netbacks Per Unit Of Production

For the year ended December 31

	Bitumen (\$ per bbl)	Crude Oil (\$ per bbl)	Natural Gas (\$ per mcf)	Total (\$ per boe)
2008				
Production revenue	\$45.74	\$82.01	\$7.90	\$50.49
Royalties	(0.47)	(19.19)	(1.64)	(5.00)
Operating costs	(26.42)	(12.01)	(1.46)	(20.38)
Operating netback	\$18.85	\$50.81	\$4.80	\$25.11
2007				
Production revenue	–	\$52.80	\$6.38	\$43.22
Royalties	–	(12.57)	(0.67)	(6.93)
Operating cost	–	(11.05)	(1.84)	(11.06)
Operating netback	–	\$29.18	\$3.87	\$25.23

In 2008, upstream revenues were \$265 million, compared to \$37 million in 2007, an increase of \$228 million.

Contributions to this significant revenue gain were new oil sands revenues (since declaring Pod One commercial

effective March 1, 2008) of \$198 million, higher crude oil revenues (\$16 million) and natural gas revenues (\$15 million higher), arising from increased production and higher selling prices. In the first quarter of 2008, we entered into a “costless collar” natural gas contract with a third party to receive a minimum of US\$7.50 per MMBtu and a maximum of US\$10.05 per MMBtu, on a notional quantity of 5,000 MMBtu per day of natural gas sold between April 1, 2008 and October 31, 2008. This transaction was not intended to speculate on future natural gas prices, but rather to protect the downside risk to our cash flow and the lending value of our assets. The impact of the hedge in 2008 had the effect of reducing natural gas revenues by \$831,000 or \$0.18 per Mcf.

Royalties for 2008 were \$15.7 million compared to \$5.9 million in 2007. From year to year, royalties can change based on changes in the product mix, the components of which are subject to different royalty rates. Additionally, royalty rates typically escalate with increased product prices. The most notable change in royalties this year came as a result of additional conventional crude oil and natural gas production volumes and increased product pricing. Additionally, oil sands production royalties payable at the rate of one percent of the bitumen selling price also contributed to increased royalties in 2008.

On October 25, 2007, the Government of Alberta unveiled a new royalty regime. The new regime was introduced for conventional oil, natural gas and bitumen effective January 1, 2009 and is linked to price and production levels. It applies to both new and existing oil sands projects and conventional oil and gas activities. The impact of the new royalty regime on Connacher will be dependent on, among other things, commodity prices, bitumen valuation, specified allowed costs that are recoverable in the pre-payout period for oil sands projects and production volumes.

Field operating costs of \$64 million for 2008 were substantially higher than in 2007 (\$9.4 million). Most of the increase (\$52.8 million) relates to new oil sands production since March 1, 2008. Incremental crude oil and natural gas production volumes also caused field operating costs to increase by \$1.4 million over the prior year, but on a per unit basis, operating costs for conventional production were in line with the prior year.

Oil sands field operating costs of \$52.8 million since March 1, 2008 averaged \$26.42 per barrel of bitumen produced. Approximately 40 percent of this cost was for natural gas required in the SAGD steaming process. While the production company’s production and sale of natural gas ultimately offsets this cost, the cost is required to be reported separately as part of the cost of producing bitumen. Oil sands field operating costs were impacted by a minor turnaround to clean out vessels at Pod One, by a debottlenecking to manage vapours produced by the treating process, downtime to activate a new trucking terminal and downtime for our mandated turnaround to inspect boilers and pressure safety valves. As a significant portion of other field operating cost components (such as personnel and electricity) are fixed in nature, a reduction in per unit field operating costs is anticipated to be achievable with increases in bitumen production volumes.

The overall upstream operating netback for 2008 of \$25.11 per produced boe was significantly influenced by our bitumen production, which is heavy oil and had a lower netback of \$18.85 per bitumen barrel produced, offset by increases in commodity selling prices.

Reconciliation of Upstream Operating Netback to Net Earnings

For the year ended December 31	2008		2007	
(\$000, except per unit amounts)	Total	Per boe	Total	Per boe
Upstream operating netback, as above	\$78,874	\$25.11	\$21,358	\$25.23
Interest and other income	5,434	1.73	748	0.88
Downstream margin – net	(7,490)	(2.38)	48,202	56.92
General and administrative	(11,814)	(3.76)	(8,543)	(10.09)
Stock-based compensation	(4,575)	(1.46)	(5,650)	(6.67)

Finance charges	(34,653)	(11.03)	(6,858)	(8.10)
Foreign exchange (loss) gain	(12,291)	(3.91)	26,900	31.77
Depletion, depreciation and accretion	(56,448)	(17.97)	(31,061)	(36.68)
Income taxes	5,311	1.69	(13,005)	(15.36)
Equity interest in Petrolifera earnings and dilution gain	11,049	3.52	8,870	10.47
Net earnings (loss)	\$(26,603)	\$(8.46)	\$40,961	\$48.37

Downstream Revenues and Margins

Connacher's refinery, located in Great Falls, Montana (the "Refinery"), is a strategic fit with our oil sands development. It is the closest U.S. refinery to Alberta's oil sands and processes Canadian heavy crude oil, similar to Great Divide dilbit (diluent mixed with bitumen), into a range of higher value products, including regular and premium gasoline, jet fuel and diesel as well as home heating oil and asphalt. The Refinery provides a physical hedge for our bitumen revenues by recovering a portion of the differential between West Texas Intermediate (WTI) and heavy crude oil price.

The Refinery is a complex operation and includes reforming, isomerization and alkylation processes for formulation of gasoline blends, hydro-treating for sulphur removal and fluid catalytic cracking for conversion of heavy gas oils to gasoline and distillate products. It also is a major supplier of paving grade asphalt, polymer modified grades and asphalt emulsions for road construction. The Refinery markets products in Montana and neighboring regions by truck and rail transport.

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 in greater demand during the summer. Consequently, prices and volumes for our asphalt tend to be higher in the summer and lower in the colder seasons. During the winter, most of the Refinery's asphalt production is stored in tankage for sale in the subsequent summer. Seasonal factors also affect the production and sale of gasoline, which has a higher demand in summer months and the production and sale of distillate and diesel, which has a higher winter demand. As a result, inventory levels, sales volumes and prices can be expected to fluctuate on a seasonal basis.

In 2008, refining revenues were \$374 million compared to \$313 million in 2007 because of higher refined product prices. In addition, costs of sales for 2008 were \$382 million compared to \$265 million in 2007 due to higher crude costs.

Our refining margins fell markedly in 2008, as the selling prices of refined products did not keep pace with rising crude and other feedstock costs. Our heavy oil refining margins also typically capture a portion of the difference between heavy and light crude oil costs. As this differential narrowed in 2008, so did refining margins.

The operating results of our Refinery for 2008 and 2007 are summarized below.

Refinery Throughput

Year ended December 31	2008	2007
Crude charged – bbl/d ⁽¹⁾	9,194	9,485
Refinery production – bbl/d ⁽²⁾	10,180	10,444
Sales of produced refined products – bbl/d	9,492	10,282
Sales of refined products (includes purchased products) –	10,181	10,877
Refinery utilization ⁽⁴⁾	97%	99.8%

(1)Crude charged represents the barrels per day of crude oil processed at the refinery.

(2)Refinery production represents the barrels per day of refined products yielded from processing crude and other refinery feedstocks.

(3)Includes refined products purchased for resale.

(4)Represents crude charged divided by total crude capacity of the refinery.

Feedstocks

Sour crude oil	93%	92 %
Other feedstocks & blend	7%	8 %

Revenues and Margins (\$000)

Refining sales revenue	\$374,248	\$313,050
Refining – crude oil and operating costs	381,738	264,848
Refining margin	\$(7,490)	\$48,202
Refining margin (%)	(2.0)%	15.4%

Sales of Produced Refined Products (Volume %)

Gasolines	38%	38 %
Diesel fuels	19%	17 %
Jet fuels	6%	6 %
Asphalt	33%	35%
LPG and other	4%	4 %
Total	100%	100 %

Per Barrel of Refined Product Sold

Refining sales revenue	\$100.44	\$78.85
Less: Refining – crude oil and operating costs	\$102.44	\$66.71
Refining margin	\$(2.00)	\$12.14

During the fourth quarter of 2008 the Refinery ran at reduced rates in order to allow completion and tie-in of a new hydrogen plant and upgraded hydrotreating facilities. Crude throughput for 2008 averaged 9,194 bbl/day or 97% of capacity.

By year end 2008, construction of the Ultralow Sulphur Diesel (ULSD) project was substantially completed with commissioning of a new hydrogen plant and production of ULSD scheduled for the first quarter of 2009. This project was designed and completed over a period of two years at an estimated cost of US \$20.5 million. Facilities were also completed to allow ethanol blending and marketing of ethanol blends in local markets. A new asphalt tank and rail loading facilities were also constructed in 2008.

An assessment and preliminary design study for a potential expansion of the Refinery to a capacity of 35,000 bbl/day was also undertaken. Due to market conditions, this project was deferred after the completion of initial designs.

Interest and Other Income

In 2008, the company earned interest of \$2.7 million (2007 – \$748,000) on excess funds invested in secure short-term investments. Additionally, a gain of \$2.8 million was realized on the repurchase of a portion of the Second Lien Senior Notes in the fourth quarter of 2008.

Surplus cash balances are invested in safe, secure interest bearing deposit accounts. A portion (30 percent) of the interest earned is recognized as income and a portion (70 percent) of it is credited to capitalized costs, consistent with the way interest costs are accounted for on the Second Lien Senior Notes. The company expenses 30 percent of interest costs in respect of borrowings attributed to Pod One and together with other directly related costs attributable to the Algar project, 70 percent of interest paid on the Second Lien Senior Notes has been capitalized.

General and Administrative Expenses

In 2008, general and administrative (“G&A”) expenses were \$11.8 million compared to \$8.5 million in 2007, an increase of 38 percent, reflecting increased staffing to support the operation of Great Divide and Pod One. G&A of \$5.2 million was also capitalized in 2008 (2007 – \$3.4 million).

Stock Based Compensation

The company recorded non-cash stock-based compensation charges in the respective periods as follows:

(\$000)	Years Ended December 31	
	2008	2007
Charged to G&A expense	\$4,575	\$5,650
Capitalized to property and equipment	\$1,471	\$2,220
	\$6,046	\$7,870

The reduction from the prior period is due to fewer options being granted.

The significant deterioration in equity markets, attributed to uncertainties arising from unprecedented financial and economic conditions, adversely impacted the stock market value of the company’s equity in the fourth quarter of 2008. In turn, this had a negative consequence to motivational and retention value of the company’s option plan for its employees. Concerned about the possible loss of quality staff during a period of substantial planned growth, the company offered its employees (excluding directors and officers) the opportunity to exchange significant “out of the money” options for a reduced number of new options based on the fair market value of the options. In the fourth quarter of 2008, stock-based compensation of \$675,000 was recognized (ie. expensed or capitalized) related to the exchange of options.

Finance Charges

Financing charges were \$34.7 million in 2008 compared to \$6.9 million reported in 2007. The increase resulted from interest and accretion expense related to the Second Lien Senior Notes issued in late 2007, financing costs related to the company’s decision to terminate the Revolving Credit Facilities and a full year of interest and accretion expense on the Convertible Debentures.

Foreign Exchange Gains and Losses

As the value of the Canadian dollar weakened in the latter part of 2008, the company recorded an unrealized foreign exchange loss of \$131 million with respect to the translation of its U.S. dollar denominated Second Lien Senior Notes. This loss was partially offset by a gain of \$98 million realized in November 2008 when the company monetized its cross-currency and interest rate swaps, the reversal of a \$9 million mark to market loss reported at December 31, 2007 and by unrealized gains of \$12 million on translating U.S. dollar-denominated cash balances.

In 2007, the company repaid another U.S. dollar-denominated loan when the Canadian dollar was stronger and realized a foreign exchange gain of \$30 million, which gain then was partially offset by an unrealized loss of \$3 million on translating US dollar denominated cash balances.

Depletion, Depreciation and Accretion (“DD&A”)

Depletion expense is calculated using the unit-of-production method based on total estimated proved reserves. DD&A in 2008 was \$45 million, a 96 percent increase from last year (2007 – \$23 million) primarily due to significant increases in production, depletion of Pod One capitalized costs commencing on March 1, 2008 and to the significant additions made to capital assets in 2008. This equates to \$ 14.33 per boe of production compared to \$27.16 per boe last year.

Capital costs of \$297 million (2007 – \$413 million) related to oil sands projects in the pre-production stage and undeveloped land acquisition costs of \$14.2 million (2007 – \$14.7 million), were excluded from the depletion calculation. However, future

development costs of \$1.3 billion (2007 – \$14.3 million) for proved undeveloped reserves were included in the depletion calculation. Costs excluded from the depletion pool have been separately tested for impairment.

Included in DD&A is MRCI refinery depreciation of \$8.2 million (2007 – \$5.3 million), depreciation of furniture, equipment and leaseholds of \$1.5 million (2007 – \$1.2 million) and a charge of \$1.7 million (2007 – \$1.6 million) in respect of the company's estimated asset retirement obligations ("ARO"). The ARO charges will continue to be necessary in the future to accrete the currently booked discounted liability of \$26.4 million to the estimated total undiscounted liability of \$47.3 million over the remaining economic life of the company's oil and gas properties.

Ceiling Test

Oil and gas companies are required to compare the recoverable value of their oil and gas assets to their recorded carrying value at the end of each reporting period. Excess carrying values over ceiling value are to be written off against earnings. No write-down was required for any reporting period in 2008 or 2007.

Income Taxes

The income tax recovery of \$5.3 million in 2008 includes a current tax recovery of \$12.9 million, principally related to US refinery operations and a future income tax provision of \$7.6 million reflecting the change in tax pools during the year.

At December 31, 2008 the company had approximately \$89 million of non-capital losses which expire over time to 2028, \$551 million of deductible resource pools and \$26 million of deductible financing costs. The future income tax benefit of these have been recognized at December 31, 2008. Additionally, the company had \$167 million of capital losses available to reduce capital gains in future. These capital losses have no expiry and their future income tax benefit has not been recognized due to uncertainty of their realization at December 31, 2008.

The income tax provision of \$13 million in 2007 includes a provision for current income taxes of \$11 million related to the Refinery and \$2 million related to Canadian capital and other taxes.

Equity Interest In Petrolifera Petroleum Limited ("Petrolifera") Earnings

Connacher accounts for its 24 percent equity investment in Petrolifera using the equity method of accounting. Connacher's equity interest share of Petrolifera's earnings in 2008 was \$3.1 million (2007 – \$7.0 million).

Dilution Gain

In April 2007, Connacher exercised warrants to purchase 1.7 million common shares in Petrolifera for total consideration of \$5.1 million. As a result, the company maintained its then 26 percent equity interest as other Petrolifera shareholders similarly exercised warrants on identical terms. Connacher booked a dilution gain of \$1.9 million as a consequence of these transactions.

In June 2008, Petrolifera issued an additional 4.4 million common shares to raise \$40 million. Connacher did not subscribe for any of these shares. Consequently, Connacher's equity interest in Petrolifera was reduced from 26 percent to 24 percent. This change resulted in a dilution gain of \$8 million, recognized by Connacher in 2008.

Net Earnings

For 2008 the company reported a loss of \$26.6 million (\$0.13 per basic and diluted share outstanding). This compares to earnings of \$41.0 million or \$0.20 per basic and diluted share for 2007. The change year over year is explained in the income and expense components herein. Included in the year's loss were non-cash charges totaling \$80 million. These included DD&A, foreign exchange, future taxes, finance charges, stock-based compensation and the write-off of deferred financing charges and front end engineering and design studies related to the deferral of refinery expansion plans.

Shares Outstanding

For 2008, the weighted average number of common shares outstanding was 210,793,657 (2007 – 200,092,469) and the weighted average number of diluted shares outstanding, as calculated by the treasury stock method, was 214,647,452 (2007 – 202,766,939).

As at March 19, 2009, the company had the following securities issued and outstanding:

211,290,790 common shares;

16,025,620 share purchase options;

387,495 share units under the share awards plan; and

20,010,000 common shares issuable upon conversion of the \$100,050,000 convertible debentures.

Liquidity and Capital Resources

The current financial crisis has severely reduced liquidity in capital markets. Economic uncertainty and significant volatility in commodity markets and stock markets have also occurred around the world. Connacher's share price and the trading value of its Second Lien Senior Notes and Convertible Debentures have been adversely affected by the uncertainty of future crude oil and natural gas prices, as well as by the impact of anticipated new environmental regulations, which could affect the economics of our business. Notwithstanding the challenges imposed by this crisis and current economic conditions, management believes that the company has attractive internally-generated growth prospects which, with our cash balances and the impact of an improvement in commodity prices, will allow us to expand our operations. In the interim, however, lower world oil prices are expected to result in lower per unit revenues, netbacks, cash flow and earnings. We anticipate increasing production and sales volumes in 2009 which could partially offset the impact of lower world commodity prices.

In response to these economic and market conditions, the company has reduced its capital expenditure budget for the 2009 winter exploration and oil sands delineation program and curtailed some capital projects (notably, the expansion of our downstream refining capacity and the construction of an oil sands sales and diluent pipeline) and we suspended the construction of Algar until there is more visibility of improved industry conditions. We anticipate this will be evidenced by improved commodity pricing, improved credit and capital markets and improved general economic conditions.

To date approximately \$150 million has been invested in Algar. The majority of the long-lead equipment items have been built. The road to the plant site and well pads have also been constructed. The site is considered ready for resumption of civil construction at a later date. We estimate that it will require approximately 275 days and approximately \$209 million of capital to complete the project once a decision to resume construction is made.

At December 31, 2008, the company had working capital of \$198 million (December 31, 2007 – \$390 million), including \$224 million of cash on hand (December 31, 2007 – \$392 million).

In light of the volatility of current commodity prices and the U.S.:Canadian dollar exchange rate and their significance to the company's operating performance, management continues to assess alternative hedging strategies to protect the company's cash flow from the risk of potentially lower crude oil and refined product pricing and adverse exchange rate fluctuations. Although the company's integrated business model provides some protection, it does not provide a perfect hedge. The purpose of any such hedge(s) would be to ensure sufficient cash flow to continue to service indebtedness, complete capital projects and protect the credit capacity of its oil and gas reserves in a volatile and weak commodity price and weakened economic environment.

In order to mitigate commodity price exposure, in November 2008 the company entered into a foreign exchange collar which throughout 2009 sets a floor of CAD \$1.1925 per US \$1.00 and a ceiling of CAD \$1.3000 per US \$1.00 on a notional amount of US \$10,000,000 of production revenue per month.

Additionally, in early 2009 the company entered into WTI hedges at crude oil prices of US \$46.00/bbl and US \$49.50/bbl on a notional volume of 5,000 barrels of oil per day for a significant portion of 2009.

For 2008, cash flow was \$55 million (\$0.26 per basic and fully diluted share outstanding), 22 percent higher than in 2007.

Cash flow and cash flow per share do not have standardized meanings prescribed by GAAP and therefore may not be comparable to similar measures used by other companies. Cash flow includes all cash flow from operating activities and is calculated before changes in non-cash working capital, pension funding and asset retirement expenditures. The most comparable measure calculated in accordance with GAAP is net earnings. Net earnings are reconciled with cash flow on the Consolidated Statement of Cash Flows and below.

Reconciliation of net earnings to cash flow from operations before working capital and other changes:

(\$000)	Twelve months ended December 31	
	2008	2007
Net earnings (loss)	\$(26,603)	\$40,961
Items not involving cash:		
Depletion, depreciation and accretion	56,448	31,061
Stock-based compensation	4,575	6,071
Non-cash financing charges	8,934	2,168
Future income tax provision	7,623	27
Employee future benefits	730	447
Realized foreign exchange transactions	(105,414)	(29,754)
Unrealized foreign exchange loss	122,342	2,854
Gain on repurchase of Second Lien Senior Notes	(2,769)	–
Dilution gain	(7,964)	(1,917)
Equity interest in Petrolifera loss (earnings)	(3,085)	(6,953)
Cash flow from operations before working capital and other charges	\$54,817	\$44,965

Cash flow per share is calculated by dividing cash flow by the calculated weighted average number of shares outstanding. Management uses this non-GAAP measurement (which is a common industry parameter) for its own performance measure and to provide its shareholders and investors with a measurement of the company's efficiency and its ability to fund future growth expenditures.

The company's only financial instruments are cash, restricted cash, accounts receivable and payable, amounts due from Petrolifera, the Convertible Debentures and the Second Lien Senior Notes. The company maintains no off-balance sheet financial instruments, other than the hedges noted above.

As the Second Lien Senior Notes are denominated in US dollars, there is a foreign exchange risk associated with their semi-annual interest payments and the repayment of principal in 2015 using Canadian currency to acquire US currency.

Connacher's objectives in managing its cash, debt and equity, its capital structure and its future capital requirements are to safeguard its ability to meet its financial obligations, to maintain a flexible capital structure that allows multiple financing options when a financing need arises and to optimize its use of short-term and long-term debt and equity at an appropriate level of risk.

The company manages its capital structure and follows a financial strategy that considers economic and industry conditions, the risk characteristics of its underlying assets and its growth opportunities. It strives to continuously improve its credit rating and reduce its cost of capital. Connacher monitors its capital structure using a number of financial ratios and industry metrics to ensure its objectives are being met.

	As at December 31	
Connacher's capital structure is composed of: (\$000)	2008	2007
Long term debt ⁽¹⁾	\$778,732	\$664,462
Shareholders' equity		
Share capital, contributed surplus and equity component	437,899	444,086
Accumulated other comprehensive income (loss)	7,802	(13,636)
Retained earnings	23,386	49,989
Total	\$1,247,819	\$1,144,901
Debt to book capitalization ⁽²⁾	62%	58%
Debt to market capitalization ⁽³⁾	81%	44%

(1) Long-term debt is stated at its carrying value, which is net of original issue discounts, transaction costs and the Convertible Debentures' equity component value.

(2) Calculated as long-term debt divided by the book value of shareholders' equity plus long-term debt.

(3) Calculated as long-term debt divided by the year end market value of shareholders' equity plus long-term debt.

Connacher had a high calculated ratio of debt to capitalization at December 31, 2008. This is due to pre-funding the full cost of Algar in 2007 through the issuance of US \$600 million of Second Lien Senior Notes, a portion of the proceeds of which was used to repay indebtedness incurred previously for Pod One. As at December 31, 2008, the company's net debt (long-term debt, net of cash on hand) was \$555 million, its net debt to book capitalization was 44 percent and its net debt to market capitalization was 57 percent.

The company had the following long-term debt outstanding, as at December 31

(\$000)	2008	2007
Second Lien Senior Notes, 10 1/4 %, due December 15,	\$694,086	\$570,594
Convertible Debentures, 4 3/4%, due June 30, 2012	84,646	81,133
Cross-currency interest rate swap	–	12,735
Total	778,732	664,462
Less current portion of long-term debt	–	–
Long-term portion	\$778,732	\$664,462

Sensitivity Analysis

The following table shows sensitivities to cash flow as a result of changes to oil prices, production volumes and foreign exchange rates. The analysis is based on recent prices and production volumes.

	Change	\$ million	\$/share ⁽¹⁾
WTI price ⁽²⁾	\$5.00/bbl	6	0.03
Bitumen production	500 bbl/d	3	0.01
Exchange rate (US/Canadian)	\$0.05	6	0.03

(1) Based on 211 million shares outstanding at December 31, 2008

(2) After royalties

Recent Financings

Second Lien Senior Notes

In December 2007 the company issued US \$600 million Second Lien Senior Notes at an issue price of 98.657 for net proceeds of US \$575 million after fees and expenses. A portion of the proceeds was used to repay the US \$180 million Oil Sands Term Loan, to fully repay drawn amounts and then cancel the company's conventional oil and gas line of credit and to fund a one-year interest reserve account in the amount of US \$63.6 million. The remainder of the proceeds were targeted to fund the construction of Algar, the company's second 10,000 bbl/d SAGD oil sands project. The Second Lien Senior Notes bear interest at a rate of 10.25%, payable semi-annually on June 15 and December 15. No principal payments are due until the maturity date of December 15, 2015. The Second Lien Senior Notes are secured by a second lien covering substantially all of the company's assets with the exception of its investment in Petrolifera. To December 31, 2008, the proceeds of the Second Lien Senior Note financing have been utilized as follows:

(\$000s)	As stated at the time of financing ⁽¹⁾	As actually applied ⁽¹⁾
Gross proceeds	\$576,380	\$591,942
Underwriters commissions and issue costs	(13,380)	(16,493)
Repayment of Oil Sands Term Loan	(186,000)	(180,000)
Funding interest reserve account	(66,000)	(63,600)
Repay the conventional line of credit	–	(2,500)
Net proceeds for the construction of Algar ⁽²⁾	\$311,000	\$329,349

(1) The Canadian dollar equivalent changed between the dates of announcing and closing the financing due to significant changes in the US:CAD exchange rates in late 2007.

(2) Net proceeds are available for funding capital expenditures relating to Algar. As at December 31, 2008, approximately \$81 million of cash had been used to fund the Algar expenditures incurred, another \$48 million of incurred expenditures is included in accounts payable and a further \$21 million of costs (primarily long-lead equipment items) has been requisitioned.

In order to partially mitigate the foreign currency translation exposure on its U.S. dollar denominated Second Lien Senior Notes, the company entered into cross currency and interest rate swaps on a notional US \$300 million amount. To capitalize on a weak Canadian dollar and for the prospect of adding significant additional cash to its treasury at no cost or shareholder dilution, the cross-currency and interest rate swaps were terminated in November 2008 and the company realized cash proceeds of \$89.1 million. The company will again consider hedging this U.S.-dollar denominated debt in future, again, if appropriate circumstances warrant.

In the fourth quarter of 2008, the company repurchased US \$8 million face value of Second Lien Senior Notes in the market at a discount, cancelled the notes and realized a gain of \$2.7 million.

Flow-through Shares

In November 2007, the company issued 10,450,000 common shares on a flow-through basis at \$5.00 per share for gross proceeds of \$52.25 million. Proceeds from this financing were used in December 2007 and in the first quarter of 2008 to

drill exploratory core holes and to shoot 3D seismic in order to further delineate the company's oil sands reserves and resources. The company renounced the income tax benefits of these expenditures (\$52.25 million) to the subscribing investors effective December 31, 2007.

Proceeds of the flow-through share financing were utilized as follows:

(\$000s)	As stated at the time of financing	As actually applied
Gross proceeds	\$52,250	\$52,250
Underwriters' commissions and issue costs	(2,913) ⁽¹⁾	(2,748) ⁽¹⁾
Exploration expenditures	(52,250)	(52,250)
	\$ –	\$ –

(1) Paid from general funds of the company.

Revolving Credit Facilities

At December 31, 2008 the company had available revolving lines of credit in the amounts of CAD \$150 million and US \$50 million. No amounts were drawn under the revolving credit facilities at December 31, 2008 other than as security for letters of credit in the amount of \$6 million. Subsequent to December 31, 2008, the company terminated the Revolving Credit Facilities. The unamortized costs of establishing this facility (\$3.75 million) were expensed in 2008.

Subsequent to year end Connacher put in place a \$20 million demand operating facility for the purpose of issuing letters of credit. The facility is secured by cash and a first lien claim on certain assets of the company.

Convertible Debentures

On May 25, 2007 Connacher issued senior unsecured subordinated convertible debentures ("Convertible Debentures") with a face value of \$100,050,000. The Convertible Debentures mature June 30, 2012, unless converted prior to that date and bear interest at an annual rate of 4.75 percent, payable semiannually on June 30 and December 31. The Convertible Debentures are convertible at any time into common shares at the option of the holder at a conversion price of \$5.00 per share.

Proceeds of the Convertible Debenture financing were utilized as follows.

(\$000s)	As stated at the time of financing	As actually applied
Gross proceeds	\$100,050	\$100,050
Underwriters' commissions and issue costs	(3,252)	(4,040)
Net proceeds	96,798	96,010
Repay short-term debt	(52,500)	(52,500)
Fund Pod One and other oil sands projects	(35,000)	(37,500)
Fund conventional capital program	(8,298)	(4,810)
Fund operating expenses	(1,000)	(1,200)
Balance	–	–

The Convertible Debentures are redeemable in whole or in part by the company, on or after June 30, 2010, at a redemption price equal to 100 percent of the principal amount of the Convertible Debentures to be redeemed, plus accrued

and unpaid interest, provided that the market price of the company's common shares is at least 120 percent of the conversion price of the Convertible Debentures.

The conversion feature of the Convertible Debentures has been accounted for as a separate component of equity in the amount of \$16,823,000. The remainder of the net proceeds of the Convertible Debentures of \$79,243,000 has been recorded as long-term debt, which will be accreted up to the face value of \$100,050,000 over the five-year term of the Convertible Debentures. Accretion and interest paid are recorded as finance charges on the Consolidated Statement of Operations and Retained Earnings. If the Convertible Debentures are converted to common shares, the value of the conversion feature will be reclassified to share capital along with the principal amounts converted.

Commitments, Contingencies, Guarantees, Contractual Obligations and Off Balance Sheet Arrangements

The company's annual commitments under leases for office premises and operating costs, software license agreements, other equipment and long term debt are as follows:

Contractual obligations (\$000)	2009	2010-2012	2013-2014	Subsequent to 2014	Total
Long-term debt	–	100,050	–	721,056	821,106
Asset retirement obligations	–	413	–	25,983	26,396
Operating leases	3,739	8,083	5,259	6,574	23,655
Employee future benefits	676	–	–	–	676
Total	4,415	108,546	5,259	753,613	871,833

The above table excludes ongoing crude oil and refined product purchase commitments of the Refinery, which are in the normal course of business and are contracted at market prices, where the products are for resale into the market.

Additionally, the company has various guarantees and indemnifications in place in the ordinary course of business, none of which are expected to have a significant impact on the company's financial statements or operations.

The company has not entered into any off-balance sheet arrangements, other than the hedging arrangements addressed herein.

Property and Equipment Additions

Property and equipment additions totaled \$352 million in 2008 and \$323 million in 2007. A breakdown of the expenditures follows.

(\$000)	Twelve months ended December 31	
	2008	2007
Crude oil, natural gas and oil sands expenditures	\$327,452	\$307,047
Refinery expenditures	24,284	15,915
	\$351,736	\$322,962

For 2008, conventional and oil sands exploration expenditures totaled \$327 million; Algar facility and equipment expenditures totaled \$128 million; conventional oil and natural gas facilities and drilling programs totaled \$56 million; Pod One turnaround costs, a horizontal well re-drill, truck loading facilities and capitalized pre-operating costs totaled \$30 million; and capitalized interest, G&A, lease acquisitions, corehole exploratory drilling, seismic and other expenditures

totaled \$113 million. The capital program added significant additional natural gas production and significant additions to proved, probable and possible reserves and to contingent and prospective resources, as reported in the company's Annual Information Form for the year ended December 31, 2008.

At our refinery, \$14 million was incurred on the ultra low sulphur diesel conversion project in 2008. Total 2008 capital expenditures tracked closely to our 2008 capital budget. The balance of \$10 million was incurred for additional tankage, maintenance, environmental enhancements and expansion study projects.

In 2007, capital costs were primarily focused on the construction of the Great Divide Pod One facility, core hole exploratory drilling, SAGD well pairs and the upstream drilling program.

Fourth Quarter

(\$000)	For the three months ended		
	December 31, 2008	September 30, 2008	December 31, 2007
REVENUE			
Upstream, net of royalties	\$41,957	\$96,291	\$7,376
Downstream	56,803	127,726	75,733
Interest and other income	3,349	541	231
	102,109	224,558	83,340
EXPENSES			
Upstream - diluent purchases and operating costs	39,258	52,125	2,826
Upstream transportation costs	4,815	6,256	-
Downstream - crude oil purchases and operating costs	66,964	125,455	70,638
General and administrative	3,063	2,774	1,711
Stock-based compensation	1,088	790	1,213
Finance charges	12,138	7,786	2,603
Foreign exchange loss (gain)	5,643	1,439	2,555
Depletion, depreciation and accretion	20,191	14,968	8,658
	153,160	211,593	90,204
Earnings (loss) before income taxes and other items	(51,051)	12,965	(6,864)
Current income tax provision (recovery)	(14,798)	387	(313)
Future income tax provision (recovery)	8,180	1,233	(4,878)
Earnings (loss) before other items	(44,433)	11,345	(1,673)
Equity interest in Petrolifera earnings	841	854	812
Dilution gain (loss)	-	(60)	21

NET EARNINGS (LOSS)	\$ (43,592)	\$12,139	\$(840)
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Reconciliation of net earnings (loss) to cash flow from operations before working capital and other changes

(\$000)	For the three months ended		
	December 31, 2008	September 30, 2008	December 31, 2007
Net earnings (loss)	\$ (43,592)	\$12,139	\$(840)
Items not involving cash:			
Depletion, depreciation and accretion	20,191	14,968	8,658
Stock based compensation	1,088	790	1,299
Non-cash financing costs	2,389	1,238	1,034
Employee future benefits	386	117	88
Future income tax provision (recovery)	8,180	1,233	(4,878)
Unrealized foreign exchange loss	115,694	1,439	32,309
Realized foreign exchange transactions	(105,414)	-	(29,754)
Gain on repurchase of Second Lien Senior Notes	(2,769)	-	-
Dilution (gain) loss	-	60	(21)
Equity interest in Petrolifera earnings	(841)	(854)	(812)
Cash flow from operations before working capital and	\$ (4,688)	\$31,130	\$7,083

For the fourth quarter 2008, upstream production was 10,341 boe/d compared to 2,233 boe/d in the fourth quarter of 2007 and 9,966 boe/d in the third quarter of 2008. This was achieved despite the curtailment of bitumen production at Pod One in mid-December 2008. Revenue was \$102 million compared to \$83 million in the fourth quarter of 2007 and \$225 million in the third quarter of 2008.

The collapse of crude oil prices late in 2008 had a significant adverse impact on oil sands economics. As a producer of bitumen in Alberta, we reacted quickly to weaker crude oil prices, widened heavy oil differentials and challenging operating costs by curtailing production at Pod One in December 2008. Subsequently, within about one month of this curtailment, we were fortunately able to restore our operations to full capacity, because of steps we took to capitalize on contango in the crude oil price futures market and other factors, which improved our selling price at Pod One. Accordingly, we are now in the midst of ramping volumes up to pre-shutdown levels, which were approaching 10,000 bbl/d in December, 2008. At those production levels, our steam/oil ratios ("SOR's") were favorable, at around three times overall and approaching two times at some of our better wells, before the curtailment. We anticipate again achieving these metrics in 2009.

Refining revenues and margins in the fourth quarter were impacted by lower commodity prices, reduced product demand for gasoline and diesel due to economic circumstances and for asphalt due to seasonality demands and reduced processing volumes to allow completion and tie-in of our new hydrogen and upgraded hydro treating facilities.

In the fourth quarter of 2008, interest and other income included a gain of \$2.8 million realized upon the re-purchase and cancellation of US \$8 million face value of Second Lien Notes, as the notes were purchased at a discount in the open market.

In the fourth quarter of 2008, the company also monetized the cross-currency and interest rate swaps by unwinding them and realized net cash proceeds of \$89.1 million, of which \$97.6 million was recorded as a realized foreign exchange gain, \$2.6 million was recorded as a finance charge and \$5.9 million was capitalized to property and equipment.

For the three months ended December 31, 2008, the company sustained a loss of \$43.6 million (\$0.21 per share) compared to a loss of \$840,000 (nil per share) in the fourth quarter of 2007 and net earnings of \$12.1 million (\$0.06 per share) in the third quarter of 2008. This loss was primarily due to non-cash charges totaling \$39 million. These charges included foreign exchange, future taxes and write-offs of deferred financing costs and front end engineering and design studies related to the deferral of refinery expansion plans. Operating cash flow was negative \$4.7 million in the fourth quarter of 2008 (\$0.02 per share) compared to positive cash flow of \$7.1 million (\$0.03 per share) in the fourth quarter of 2007 and cash flow of \$31.1 million (\$0.15 per share) in the third quarter of 2008. The primary reasons for these period to period variations are noted above.

Outlook

We expect 2009 will continue to be challenging. We have already experienced challenges during the first few months of the year. However, we anticipate a much improved full year contribution from our refining operations primarily due to anticipated healthy asphalt markets, with wider margins, as newly-announced U.S. government infrastructure projects are anticipated to result in an unprecedented demand for asphalt. This product is currently in short supply in the United States. This improvement should start to be apparent in the second quarter of 2009. We also anticipate positive net operating income from our upstream operations during 2009 as a result of hedging and marketing activities and anticipated reductions in transportation and operating costs.

We have significant cash balances and together with anticipated positive operating income in 2009, we anticipate being able to meet all our financial obligations throughout 2009, even if crude oil prices stay at WTI US\$45.00/bbl for the balance of this year. We continue to believe preserving our liquidity and protecting our assets are the priority responsibilities for 2009. We have ample identified reserves and resources to remain confident of our future growth prospects and we believe energy prices will improve as the year unfolds. To stabilize our outlook in a volatile period and protect against the possibility of renewed crude oil weakness, we have arranged WTI hedges at prices of US\$46/bbl and US\$49.50/bbl on approximately one half of our bitumen production for most of 2009. Relative to our consumption of natural gas at Pod One we have a built-in physical hedge with our own natural gas production at Marten Creek, Latornell, Seal and other areas. This minimizes the impact of volatility in natural gas prices on our overall operations.

The company's business plan anticipates long-term growth, with continued increases in revenue and cash flow from Pod One, conventional crude oil and natural gas production, while in due course completing the Algar project and subsequently expanding all aspects of our business. A more cautious short-term approach has recently been adopted in light of existing adverse capital and commodity market conditions.

In response to the current conditions, the company reduced its capital expenditure budget for the 2009 winter exploration and oil sands delineation program and curtailed some capital projects (notably, the expansion of our downstream refining capacity and the construction of an oil sands sales and diluent pipeline). Construction of Algar was suspended until we see more visibility in improved industry conditions which we anticipate will be evidenced by improved commodity pricing, improved capital markets and improved general economic conditions.

To date we have invested approximately \$150 million in Algar, having built the majority of the long-lead equipment items, constructed the road to the site and prepared the site for resumption of civil construction at a later date. Approximately 275 days and, based on current estimates, approximately \$209 million, will be required to complete the project.

In view of changed capital market conditions, we have elected to preserve liquidity by reducing our 2009 capital expenditures to \$123 million from \$373 million as follows:

(\$million)	New	Original
Upstream		
Conventional	\$13	\$15
Pod One	18	20
Algar	29	208
Algar capitalized items	30	69
Cogeneration	4	22
Exploration	9	10
EIA and other	3	3
Downstream		
Refining	17	26
Total	\$123	\$373

Related Party Transactions

In 2008 the company paid professional legal fees of \$1.1 million (2007 – \$667,000) to a law firm in which the company’s Corporate Secretary is a partner. Transactions with the foregoing related parties occurred within the normal course of business and have been measured at their exchange amount on normal business terms. The exchange amount is the amount of consideration established and agreed to by the related parties.

A portion of the company’s conventional crude oil and natural gas exploration and drilling activities, which activities are anticipated to continue in the future, was conducted in an industry-standard joint venture arrangement with a company, an officer of which is also a director of Connacher. Transactions with the joint venture partner occurred within the normal course of business and have been measured at their exchange amount on normal business terms. The exchange amount is the amount of consideration established and agreed to by the company and the joint venture partner. These capital expenditures incurred to date are not considered material to the company’s overall capital expenditure program.

Significant Accounting Policies and Application of Critical Accounting Estimates

The significant accounting policies used by the company are described below. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Changes in these estimates and assumptions may have a material impact on the company’s financial results and condition. The following discusses such accounting policies and is included herein to aid the reader in assessing the critical accounting policies and practices of the company and the likelihood of materially different results being reported. Management reviews its estimates and assumptions regularly in light of changing circumstances, economic and otherwise. The emergence of new information and changed circumstances may result in changes to estimates and assumptions which could be material and the company might realize different results from the application of new accounting standards promulgated, from time to time, by various regulatory rule-making bodies.

The following assessment of significant accounting polices is not meant to be exhaustive.

Reserve Estimates

Under Canadian Securities Administrators’ “National Instrument 51-101-Standards of Disclosure for Oil and Gas Activities” (“NI 51-101”), proved reserves are those reserves that can be estimated with a high degree of certainty to be

recoverable. In accordance with this definition, the level of certainty should result in at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated reserves. In the case of probable reserves, which are less certain to be recovered than proved reserves, NI 51-101 states that it must be 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 reserves less certain to be recovered than probable reserves. There is at least a 10 percent probability that the quantities actually recovered will exceed the sum of proved plus probable plus possible reserves.

The company's oil and gas reserve estimates are made by independent reservoir engineers using all available geological and reservoir data as well as historical production data. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the company's plans. The reserve estimates can also be used in determining the company's borrowing base for its credit facilities and may impact the same upon revision or changes to the reserve estimates. The effect of changes in proved oil and gas reserves on the financial results and position of the company is described below.

Full Cost Accounting for Oil and Gas Activities

The company uses the full cost method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development are capitalized whether successful or not. The aggregate of net capitalized costs and estimated future development costs is depleted using the unit-of-production method based on estimated proved oil and gas reserves. A change in estimated total proved reserves could significantly affect the company's calculation of depletion.

Major Development Projects and Unproved Properties

Certain costs related to acquiring and evaluating unproved properties are excluded from net capitalized costs subject to depletion until proved reserves have been determined or their value is impaired. Costs associated with major development projects are not depleted until commencement of commercial production. All capitalized costs are reviewed quarterly and any impairment is transferred to the costs being depleted or, if the properties are located in a cost centre where there is no reserve base, the impairment is charged directly to income.

All costs related to the Great Divide oil sands project are being capitalized to specific projects, or "Pods", pending commencement of commercial operations from each Pod. Upon commencement of commercial operations of a Pod, the related capital costs and estimates of future capital requirements for such Pod will be added to the company's depletable costs and depleted under the unit-of-production method based on the company's total proved reserves. Effective March 1, 2008, the company's first oil sands project, Pod One, was declared commercially operative and its related costs were added to the company's depletable cost pool.

Ceiling Test

The company is required to review the carrying value of all property, plant and equipment, including the carrying value of its conventional oil and gas assets and its commercially operative oil sands properties, for potential impairment. Impairment is indicated if the carrying value of the long-lived asset or oil and gas cost centre is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings.

The ceiling test is based on estimates of reserves prepared by qualified independent evaluators, production rate, crude oil, bitumen and natural gas prices, future costs and other relevant assumptions. By their nature reserve estimates are subject to measurement uncertainty and the impact of ceiling test calculations on the consolidated financial statements for changes in reserve estimates could be material.

Asset Retirement Obligations

The company is required to provide for future removal and site restoration costs by estimating these costs in accordance with existing laws, contracts or other policies. These estimated costs are charged to earnings and the appropriate liability

account over the expected service life of the asset. When the future removal and site restoration costs cannot be reasonably determined, a contingent liability may exist. Contingent liabilities are charged to earnings only when management is able to determine the amount and the likelihood of the future obligation. The company estimates future retirement costs based on current costs as estimated by the company's engineers adjusted for inflation and credit risk. These estimates are subject to management uncertainty.

Legal, Environmental Remediation and Other Contingent Matters

In respect of these matters, the company is required to determine whether a loss is probable based on judgment and interpretation of laws and regulations and determine if such a loss can be estimated. When any such loss is determined, it is charged to earnings. Management continually monitors known and potential contingent matters and makes appropriate provisions by charges to earnings when warranted by circumstance.

Income Taxes

The company follows the liability method of accounting for income taxes. Under this method tax assets are recognized when it is more than likely realization will occur. Tax liabilities are recognized for temporary differences between recorded book values and underlying tax values. Rates used to determine income tax asset and liability amounts are enacted tax rates expected to be used in future periods when the timing differences reverse. The period in which a timing difference reverses are impacted by future income and capital expenditures. Rates are also affected by legislation changes. These components can impact the charge for future income taxes.

Stock-Based Compensation

The company uses the fair value method to account for stock options. The determination of the amounts for stock-based compensation are based on estimates of stock volatility, interest rates and the term of the option. These estimates by their nature are subject to measurement uncertainty.

Convertible Debentures

The Convertible Debentures have been recorded as a compound financial instrument in accordance with Section 3863 of the Canadian Institute of Chartered Accountants, or CICA, Handbook. The fair value of the liability component was determined at the date of issue based on our incremental borrowing rate for debt with similar terms. The amount of the equity component was determined as a residual after deducting the amount of the liability component from the face value of the issue.

Share Award Plan

Obligations for payments in cash or common shares under our share award plan for non-employee directors are accrued as compensation expense over the vesting period. Fluctuations in the price of our common shares change the accrued compensation expense and are recognized when they occur.

Refinery Accounting

Since its acquisition in March 2006, the Refinery's financial results are reported in accordance with Canadian GAAP and have been consolidated with our other business units. The preparation of the Refinery's financial results require certain estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities as of the date of the financial statements. Actual results may differ from those estimates under different assumptions or conditions. Our management considers the following new accounting policies to be the most critical to understanding the judgments that are involved and the uncertainties that could impact on our results of operations, financial condition and cash flow.

Inventory Valuation

Crude oil and refined product inventories are stated at the lower of cost or net realizable value.

Since acquiring the refining assets in March 2006, management re-evaluated the inventory costing method and has chosen the average cost method in order to conform to (then) impending (now mandated) Canadian GAAP changes. The effect of

this change was to decrease inventory by \$2.5 million at December 31, 2006. Net realizable value is determined using current estimated selling prices.

Maintenance Costs

The Refinery units require regular major maintenance and repairs, which are commonly referred to as “turnarounds.” Catalysts used in certain refinery processes also require routine “change-outs.” The required frequency of the maintenance varies by unit and by catalyst, but generally is every two to five years. Turnaround costs which meet the definition of property, plant and equipment are capitalized and amortized over the period to the next scheduled turnaround or change-out. In order to minimize downtime during turnarounds, contract labor as well as maintenance personnel are utilized on a continuous 24 hour basis. Whenever possible, turnarounds are scheduled so that some units continue to operate while others are down for maintenance.

Employee Future Benefits

As a consequence of the Refinery acquisition and related employment of Refinery personnel, our U.S. subsidiary, MRCI, adopted employee future benefit plans with effect from March 31, 2006. A non-contributory defined benefit retirement plan covers only the Refinery’s employees from March 31, 2006. MRCI’s policy is to make regular contributions in accordance with the funding requirements of ERISA. Benefits are to be based on the employee’s years of service and compensation. We also established defined contribution (U.S. tax code “401(k)”) plans that cover all Refinery employees from March 31, 2006. MRCI’s contributions are based on employees’ compensation and partially match employee contributions.

Long-lived Refining Assets

Depreciation and amortization is calculated based on estimated useful lives and salvage values. When assets are placed into service, estimates are made with respect to their useful lives that are believed to be reasonable. However, factors such as new technologies, competition, regulation or environmental matters could cause changes to estimates, thus impacting the future calculation of depreciation and amortization. Long-lived assets are also evaluated for potential impairment by identifying whether indicators of impairment exist and, if so, assessing whether the long-lived assets are recoverable from estimated future undiscounted cash flow. The actual amount of impairment loss, if any, to be recorded is equal to the amount by which a long-lived asset’s carrying value exceeds its fair value. Estimates of future discontinued cash flow and fair values of assets require subjective assumptions with regard to future operating results and actual results could differ from those estimates.

Goodwill

Goodwill arose on the acquisition of Luke in 2006. Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed for impairment annually. Goodwill and all other assets and liabilities have been allocated to our segments, referred to as reporting units. To assess impairment, the fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit’s assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit’s goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount.

New Significant Accounting Policies

As of January 1, 2008, the company adopted new CICA Handbook, Section 3862, “Financial Instruments – Disclosures” and Section 3863, “Financial Instruments – Presentation” which replaced former Section 3861. The new standards require disclosure of the significance of financial instruments to an entity’s financial statements, the risks associated with the financial instruments and how those risks are managed.

As of January 1, 2008, the company also adopted new CICA Handbook Section 1535, “Capital Disclosures” which requires entities to disclose their objectives, policies and processes for managing capital and, in addition, whether the entity has complied with any externally imposed capital requirements.

In February 2008, the CICA issued Section 3064, “Goodwill and Intangible Assets”, replacing Section 3062, “Goodwill and Other Intangible Assets” and Section 3450, “Research and Development Costs.” The new Sections will be applicable to financial statements relating to fiscal years beginning on or after October 1, 2008. Accordingly, the company will adopt the new standards for its fiscal year beginning January 1, 2009. Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062, and therefore are not anticipated to have a significant impact on the company’s financial statements.

International Financial Reporting Standards

On February 13, 2008, the Canadian Accounting Standards Board confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. The impact of the change in accounting principles on our future financial position and results of operations is not determinable or quantifiable at the present time.

We have commenced our IFRS conversion project which consists of four phases: diagnostic; design and planning; solution development; and implementation. Regular reporting is provided to management and to the Audit Committee of the Board of Directors.

We have completed the diagnostic phase, which involved a review of the differences between current Canadian GAAP and IFRS. During this phase we determined that the differences which will have the greatest impact on Connacher’s consolidated financial statements relate to accounting for exploration and development activities and property, plant and equipment impairments of capital assets, asset retirement obligations and the reporting of employee future benefits. Their financial impacts have yet to be quantified. We are currently engaged in the design and planning and the solution development phases of our project. We have identified and documented the high impact areas, including an analysis of financial system impacts and have engaged in ongoing discussions with our external auditors. The impact on our disclosure controls, internal controls over financial reporting and the impact on contracts and lending agreements will also be determined.

In September 2008 the International Accounting Standards Board issued an exposure draft to amend IFRS accounting standards in respect of property, plant and equipment as at the date of the initial transition to IFRS. That exposure draft, if adopted, would permit issuers currently using the full cost method of accounting, (as described in the CICA Handbook – Accounting Guideline 16 Oil and Gas accounting – Full Cost), to allocate the balance of property, plant and equipment as determined under Canadian GAAP to the IFRS categories of exploration and evaluation assets and development and producing properties without requiring full retroactive restatement of historic balances to the IFRS basis of accounting. If the exposure draft is adopted we anticipate using the exemption. We are also monitoring the development of guidance being prepared by a committee of the Canadian Association of Petroleum Producers on how to apply IFRS to oil and gas exploration and development activities. This is expected to be finalized in March 2009. We continue to monitor the IFRS adoption efforts of our peers and to participate in the process for a smooth transition to IFRS in advance of the deadline.

Risk Factors and Risk Management

General

Connacher is engaged in the oil and gas exploration, development, production, and refining industry. This business is inherently risky and there is no assurance that hydrocarbon reserves will be discovered and economically produced. Operational risks include competition, reservoir performance uncertainties, environmental factors, and regulatory and safety concerns. Financial

risks associated with the petroleum industry include fluctuations in commodity prices, interest rates, currency exchange rates and the cost of goods and services.

Connacher's financial and operating performance is potentially affected by a number of factors including, but not limited to, risks associated with the oil and gas, commodity prices and exchange rates, environmental legislation, changes to royalty and income tax legislation, credit and capital market conditions, credit risk for failure of performance of third parties and other risks and uncertainties described in more detail in Connacher's Annual Information Form filed with securities regulatory authorities.

Certain key risk factor some disclosed below. Reference should be made to Connacher's most recent Annual Information Form for a description of additional risk factors.

Connacher employs highly qualified people, uses sound operating and business practices and evaluates all potential and existing wells using the latest applicable technology. The company complies with government regulations and has in place an up-to-date emergency response program. Connacher adheres to environment and safety policies and standards. Asset retirement obligations are recognized upon acquisition, construction and development of the assets. Connacher maintains property and liability insurance coverage. The coverage provides a reasonable amount of protection from risk of loss; however, not all risks are foreseeable or insurable.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and are continuing in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing global credit and liquidity concerns.

Commodity Price and Exchange Rate Risks

Connacher's future financial performance remains closely linked to crude oil and natural gas commodity prices and foreign exchange rate changes which may be influenced by many factors including global and regional supply and demand, seasonality, worldwide political events and weather. These factors can cause a high degree of price volatility. For example, from 2006 to 2008, the monthly average price for benchmark WTI crude oil ranged from a low of US\$42.04/bbl to a high of US\$134.02/bbl. During the same three-year period, the natural gas AECO benchmark monthly average price ranged from a low of \$4.45/mcf to a high of \$12.11/mcf and value of the Canadian dollar traded between US\$0.77 and US\$1.09.

Crude oil and dilbit selling prices are based on U.S. dollar benchmarks that result in our realized prices being influenced by the US\$/Cdn\$ currency exchange rate, thereby creating another element of uncertainty. Should the Canadian dollar strengthen compared to the U.S. dollar, the resulting negative effect on net earnings would be partially offset with exchange gains on translating our U.S. dollar denominated debt, associated interest payments thereon and U.S. refining results to Canadian dollars for financial statement reporting purposes. The opposite would occur should the Canadian dollar weaken compared to the U.S. dollar. Cash flow is not impacted by the effects of currency fluctuations on translating our U.S. dollar denominated debt. We mitigate some of the risk associated with changes in commodity prices through the use of hedges and other derivative financial instruments. See Liquidity and Capital Resources.

Regulatory Approval Risks

Before proceeding with most major development projects, Connacher must obtain regulatory approvals, which approvals must be maintained in good standing during the currency of the particular project. The regulatory approval process involves stakeholder consultation, environmental impact assessments and public hearings, among other factors. Failure to obtain regulatory approvals, or failure to obtain them on a timely basis, could result in delays, abandonment, or restructuring of projects and increased costs, all of which could negatively impact future earnings and cash flow. Failure to maintain approvals, licenses, permits and authorizations in good standing could result in the imposition of fines, production limitations or suspension orders.

Performance

Our financial and operating performance is potentially affected by a number of factors, including, but not limited to the following.

Our ability to reliably operate our conventional and oil sands facilities is important to meet production targets. We implemented planned maintenance shutdowns in 2008 that are expected to improve reliability.

Operating costs could be impacted by inflationary pressures on labor, volatile pricing for natural gas used as an energy source in oil sands processes, and planned and unplanned maintenance. We continue to address these risks through such strategies as application of technologies that help manage operational workforce demand, offsetting natural gas purchases with our own production and an increased focus on preventative maintenance.

While fiscal regimes in Alberta and Canada are generally stable relative to many global jurisdictions, royalty and tax treatments are subject to periodic review, the outcome of which is not predictable and could result in changes to the company's planned investments and rates of return on existing investments.

Management expects that fluctuations in demand and supply for refined products, margin and price volatility, market competition and the seasonal demand fluctuations for some of our refined products will continue to impact our refining business.

There are certain risks associated with the execution of capital projects, including the risk of cost overruns. Numerous risks and uncertainties can affect construction schedules, including the availability of labor and other impacts of competing projects drawing on the same resources during the same time period.

Capital Requirements

The company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of bitumen, crude oil and natural gas reserves and refining in the future. As the company's revenues may decline as a result of decreased commodity pricing, it may be required to reduce capital expenditures. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the company to additional access to capital risk. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the company. The inability of the company to access sufficient capital for its operations could have a material adverse effect on the company's business financial condition, results of operations and prospects.

Third Party Credit Risk

An additional risk is credit risk for failure of performance by counter-parties. This risk is controlled by an evaluation of the credit risk before contract initiation and ensuring product sales and delivery contracts are made with well-known and financially strong crude oil and natural gas marketers.

The company may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners and other parties. In the event such entities fail to meet their contractual obligations to the company, such failures may have a material adverse effect on the company's business, financial condition, results of operations and prospects.

Environmental

All phases of the oil and gas and refining business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial, state and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. There has been much public debate with respect to Canada's alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases could have a material impact on the nature of oil gas and refining operations, including those of the company. Given the evolving nature of the issues related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict either the nature of those requirements or the impact on the company and its operations and financial condition.

Disclosure Controls and Procedures

The company's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the company is made known to the company's CEO and CFO by others, particularly during the period in which the annual filings are being prepared; and (ii) information required to be disclosed by the company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the company's disclosure controls and procedures at the financial year end of the company and have concluded that the company's disclosure controls and procedures are effective at the financial year end of the company for the foregoing purposes.

Internal Controls over Financial Reporting

The CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the company's financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the company's internal controls over financial reporting at the financial year end of the company and concluded that the company's internal controls over financial reporting is effective at the financial year end of the company for the foregoing purpose.

The company's CEO and CFO are required to cause the company to disclose any change in the company's internal controls over financial reporting that occurred during the company's most recent interim period that has materially affected, or is reasonably likely to materially affect, the company's internal controls over financial reporting. No material changes in the company's internal controls over financial reporting were identified during such period that has materially affected, or are reasonably likely to materially affect, the company's internal controls over financial reporting.

It should be noted that a control system, including the company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud. In reaching a reasonable level of assurance, management necessarily is required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

Quarterly Results

Fluctuations in results over the previous eight quarters are due principally to variations in oil and gas prices and production/sales volumes.

Three Months Ended	2007				2008			
	Mar 31	Jun 30	Sep 30	Dec 31	Mar 31	Jun 30	Sept 30	Dec 31
(\$000 except per share amounts)								
Revenues, net of royalties	65,923	93,266	101,991	83,340	100,656	202,016	224,558	102,109
Cash flow ⁽¹⁾	10,980	16,876	10,025	7,083	7,825	20,550	31,130	(4,688)
Basic, per share ⁽¹⁾	0.06	0.09	0.05	0.03	0.04	0.10	0.15	(0.02)
Diluted, per share ⁽¹⁾	0.05	0.08	0.05	0.03	0.03	0.10	0.14	(0.02)
Net earnings (loss)	4,984	22,228	14,589	(840)	(1,833)	6,683	12,139	(43,592)
Basic and diluted per share	0.03	0.11	0.07	(0.00)	(0.01)	0.03	0.06	(0.21)
Property and equipment additions	109,881	93,223	64,006	55,852	115,984	80,403	69,175	86,174
Cash on hand	66,209	25,375	754	392,271	323,423	232,704	236,375	223,663
Working capital surplus (deficiency)	24,027	36,320	(19,853)	389,789	287,105	234,110	200,177	197,914
Term debt	207,828	272,559	260,606	664,462	671,014	684,705	689,673	778,732
Shareholders' equity	384,593	417,793	428,764	480,439	471,559	479,477	496,509	469,087
Operating Highlights								
Upstream: Daily production / sales volumes								
Bitumen – bbl/d ⁽²⁾	–	–	–	–	1,773	6,123	6,810	7,086
Crude oil – bbl/d	905	731	781	752	996	981	957	1,187
Natural gas – mcf/d	9,665	9,017	9,413	8,889	10,493	14,220	13,188	12,405
Equivalent – boe/d ⁽³⁾	2,515	2,234	2,350	2,233	4,518	9,474	9,966	10,341
Product pricing								
Bitumen – \$/bbl ⁽²⁾	–	–	–	–	53.01	60.80	65.34	12.06
Crude oil – \$/bbl	49.09	49.79	55.98	56.79	79.50	105.28	103.60	48.13
Natural gas – \$/mcf	7.76	7.02	4.70	5.82	6.94	8.77	8.92	6.61
Selected Highlights – \$/boe ⁽³⁾								
Weighted average sales price	47.48	44.63	37.43	42.29	54.46	63.37	66.41	21.73
Royalties	11.22	3.23	6.32	6.34	7.45	6.21	4.65	3.19
Operating costs	8.54	13.08	9.00	13.77	14.32	22.78	20.41	20.76
Netback ⁽⁴⁾	27.72	28.32	22.11	22.18	32.69	34.38	41.35	(2.23)
Downstream: Refining								
Crude charged – bbl/d	9,621	9,248	9,400	9,610	9,830	9,329	9,239	8,333
Refining utilization – %	101	97	100	101	104	98	97	88
Margins – %	19	21	15	6	1	(0.1)	2	(18)
COMMON SHARE INFORMATION								
Shares outstanding at end of period (000)	198,218	198,834	199,447	209,971	210,277	211,027	211,182	211,182
Weighted average shares outstanding for the period								

Basic (000)	198,119	198,360	199,167	204,701	210,234	210,658	211,093	211,182
Diluted (000)	200,008	209,088	221,554	220,362	210,234	214,530	213,174	211,575
Volume traded during quarter (000)	55,292	61,162	70,939	52,198	63,718	107,001	112,401	110,244
Common share price (\$)								
High	4.13	4.43	4.40	4.08	3.94	5.26	4.65	2.95
Low	3.07	3.07	3.20	3.31	2.59	3.10	2.63	0.60
Close (end of period)	3.86	3.69	4.01	3.79	3.13	4.30	2.75	0.74

(1) Cash flow and cash flow per share do not have standardized meanings prescribed by Canadian generally accepted accounting principles ("GAAP") and therefore may not be comparable to similar measures used by other companies. Cash flow is calculated before changes in non-cash working capital, pension funding and asset retirement expenditures. The most comparable measure calculated in accordance with GAAP would be net earnings. Cash flow is reconciled with net earnings on the Consolidated Statement of Cash Flows and in the accompanying Management Discussion & Analysis. Management uses these non-GAAP measurements for its own performance measures and to provide its shareholders and investors with a measurement of the company's efficiency and its ability to fund its future growth expenditures.

(2) The recognition of bitumen sales from Great Divide Pod One commenced March 1, 2008, when it was declared "commercial". Prior thereto, no production volumes were reported and all operating costs, net of revenues, were capitalized.

(3) All references to barrels of oil equivalent (boe) are calculated on the basis of 6 mcf : 1 bbl. This conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Boes may be misleading, particularly if used in isolation.

(4) Netback is a non-GAAP measure used by management as a measure of operating efficiency and profitability. Netback per boe is calculated as bitumen, crude oil and natural gas revenue less royalties and operating costs divided by related production/sales volume. Netbacks are reconciled to net earnings in the accompanying MD&A.

Connacher Oil and Gas Limited

Consolidated Balance Sheets

December 31

(\$000)	2008	2007
ASSETS		
CURRENT		
Cash and cash equivalents	\$223,663	\$329,110
Restricted cash (Note 16(c))	–	63,161
Accounts receivable	20,492	25,084
Inventories (Note 5)	35,993	18,379
Due from Petrolifera (Note 6)	42	–
Prepaid expenses	2,221	2,520
Income taxes recoverable	13,875	4,279
	296,286	442,533
Property and equipment (Note 7)	985,054	671,422
Goodwill	103,676	103,676
Investment in Petrolifera (Note 6)	46,659	35,610
Deferred costs (Note 8)	–	5,587
	\$1,431,675	\$1,258,828
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	\$98,372	\$52,744
Long term debt (Note 10)	778,732	664,462
Future income taxes (Note 9)	58,296	36,818
Asset retirement obligations (Note 11)	26,396	24,365
Employee future benefits (Note 12)	792	–
	864,216	725,645
Share capital, contributed surplus and equity component (Note 13)	437,899	444,086
Accumulated other comprehensive income (loss)	7,802	(13,636)
Retained earnings	23,386	49,989
	469,087	480,439
	\$1,431,675	\$1,258,828

Commitments, contingencies and guarantees (Note 17)

Connacher Oil and Gas Limited
Consolidated Statements of Operations and Retained Earnings
Years Ended December 31

(\$000, except per share amounts)	2008	2007
REVENUE		
Upstream, net of royalties	\$	\$
Downstream	374,248	313,050
Interest and other income	5,434	748
	629,339	344,520
EXPENSES		
Upstream – diluent purchases and operating costs	156,284	9,364
Upstream transportation costs	14,499	–
Downstream – crude oil purchases and operating costs (Note 5)	381,738	264,848
General and administrative	11,814	8,543
Stock-based compensation (Note 13)	4,575	5,650
Finance charges	34,653	6,858
Foreign exchange loss (gain)	12,291	(26,900)
Depletion, depreciation and accretion	56,448	31,061
	672,302	299,424
Earnings (loss) before income taxes and other items	(42,963)	45,096
Current income tax provision (recovery) (Note 9)	(12,934)	12,978
Future income tax provision (Note 9)	7,623	27
	(5,311)	13,005
Earnings (loss) before other items	(37,652)	32,091
Equity interest in Petrolifera earnings (Note 6)	3,085	6,953
Dilution gain (Note 6)	7,964	1,917
NET EARNINGS (LOSS)	(26,603)	40,961
RETAINED EARNINGS, BEGINNING OF YEAR	49,989	9,028
RETAINED EARNINGS, END OF YEAR	\$23,386	\$49,989
EARNINGS (LOSS) PER SHARE (Note 16(a))		
Basic	\$(0.13)	\$0.20
Diluted	\$(0.13)	\$0.20

Connacher Oil and Gas Limited
Consolidated Statements of Comprehensive Income (Loss)

Year Ended December 31

(\$000)	2008	2007
Net earnings (loss)	\$(26,603)	\$40,961
Foreign currency translation adjustment	21,438	(13,506)
Comprehensive income (loss)	\$(5,165)	\$27,455

Connacher Oil and Gas Limited
Consolidated Statements of Accumulated Other Comprehensive Income (Loss)

Year Ended December 31

(\$000)	2008	2007
Balance, beginning of period	\$(13,636)	\$(130)
Foreign currency translation adjustment	21,438	(13,506)
Balance, end of period	\$7,802	\$(13,636)

Connacher Oil and Gas Limited
Consolidated Statements of Cash Flow
Years Ended December 31

(\$000)	2008	2007
Cash provided by (used in) the following activities:		
OPERATING		
Net earnings (loss)	\$(26,603)	\$40,961
Items not involving cash:		
Depletion, depreciation and accretion	56,448	31,061
Stock-based compensation (Note 13)	4,575	6,071
Financing charges – non-cash portion	8,934	2,168
Employee future benefits (Note 12a)	730	447
Future income tax provision	7,623	27
Realized foreign exchange transactions	(105,414)	(29,754)
Unrealized foreign exchange loss	122,342	2,854
Gain on repurchase of Second Lien Senior Notes	(2,769)	–
Dilution gain	(7,964)	(1,917)
Equity interest in Petrolifera earnings	(3,085)	(6,953)
Cash flow from operations before working capital and other changes	54,817	44,965
Changes in non-cash working capital (Note 16(b))	(27,583)	6,464
Pension funding (Note 12)	–	(781)
Asset retirement expenditures	(209)	(311)
	27,025	50,337
FINANCING		
Repayment of oil sands term loan	–	(180,000)
Issue of common shares, net of share issue costs	761	50,968
Increase in bank debt	–	135,856
Repayment of bank debt	–	(154,963)
Issuance of Convertible Debentures, net of issue costs (Note 10)	–	96,010
Issuance of Second Lien Senior Notes, net of issue costs (Note 10)	–	575,449
Repurchase of Second Lien Senior Notes	(6,262)	–
Deferred financing costs	(77)	(3,848)
Proceeds on unwinding of cross currency swap	97,600	–
	92,022	519,472
INVESTING		
Development of upstream and downstream properties		
Decrease in restricted cash (Note 16(c))	72,113	59,627
Exercise of Petrolifera warrants	–	(5,143)
Change in non-cash working capital (Note 16(b))	50,789	(8,669)
	(228,418)	(256,062)

NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(109,371)	313,747
Impact of foreign exchange on foreign currency denominated cash balances	3,924	(4,240)
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	329,110	19,603
CASH AND CASH EQUIVALENTS, END OF YEAR	\$223,663	\$329,110

Supplementary information – Note 16

Connacher Oil and Gas Limited

Notes To The Consolidated Financial Statements

Years Ended December 31, 2008 and 2007

1. Financial Statement Presentation

The consolidated financial statements include the accounts of Connacher Oil and Gas Limited and its subsidiaries (collectively “Connacher” or the “company”) and are presented in accordance with Canadian generally accepted accounting principles (“Canadian GAAP”). Operating in Canada and in the U.S. through its subsidiary Montana Refining Company, Inc. (“MRCI”), the company is in the business of exploring for and developing, producing, refining and marketing conventional petroleum and natural gas and the exploration, development and production of bitumen in the oil sands of northern Alberta.

2. Significant Accounting Policies

Cash and cash equivalents

Cash and cash equivalents include short-term deposits with initial maturities of three months or less, when purchased.

Inventory valuation

Crude oil and refined product inventories are stated at the lower of cost or net realizable value, determined under the weighted average cost method. Net realizable value is determined using current estimated selling prices.

Deferred costs

These amounts include costs incurred in relation to the company’s revolving credit facilities, which have been deferred and were being amortized over their term.

Petroleum, natural gas and bitumen (“upstream”) operations

The company follows the full cost method of accounting whereby all costs relating to the exploration for and development of crude oil, natural gas and bitumen reserves are capitalized on a country by country cost centre basis.

Capitalized costs of petroleum and natural gas properties and related equipment within a cost centre are depleted and depreciated using the unit-of-production method based on estimated proved reserves before royalties as determined by independent consulting engineers. For the purpose of this calculation, production and reserves of natural gas are converted to equivalent units of crude oil based on relative energy content (6:1).

The company applies a “ceiling test” to the net book value of petroleum and natural gas properties to ensure that such carrying value does not exceed the estimated fair value of the properties. The carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves and the cost, less impairment, of unproved properties exceeds the carrying value. If the carrying value is assessed to not be recoverable, the calculation compares the carrying value to the sum of the discounted cash flows expected from the production of proved and probable reserves and the cost, less impairment, of unproved properties. Should the carrying value exceed this sum, an impairment loss is recognized. The cash flows are estimated using projected future product prices and costs and are discounted using the credit adjusted risk-free interest rate.

Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion and depreciation until it is determined whether or not proved reserves are attributable to the properties or impairment occurs. Costs associated with major development projects are not depleted until commencement of commercial operations. All capitalized costs are reviewed quarterly and any impairment is transferred to the costs being depleted or, if the properties are located in a cost centre where there is no reserve base, the impairment is charged directly to earnings.

During 2008, Pod One, the company’s first oil sands project commenced commercial production. From March 1, 2008, revenue has been recognized, operating costs have been expensed and capitalized costs related to Pod One have been depleted.

To date, all costs, including financing costs, incurred in relation to the company’s Algar oil sands project in Northern Alberta, have been capitalized as the project is considered to be in the pre-production stage. Judgment is required in order to determine when commercial operations have commenced. Once it is determined that commercial operations have been achieved, revenue will be recognized, operating costs will be expensed to earnings and the capitalized costs of the project will be added to the full cost pool for depletion and ceiling test calculations. Revenues generated in the period prior to commencement of commercial operations are credited against capitalized costs.

Gains or losses on sales of properties are recognized only when crediting the proceeds to the cost pool would result in a change of 20 percent or more in the depletion and depreciation rate.

Refining (“downstream”) assets

Depreciation and amortization of refining assets is calculated based on estimated useful lives and salvage values. When assets are placed into service, estimates are made with respect to their useful lives that are believed to be reasonable. However, factors such as competition, regulation or environmental matters could cause changes to estimates, thus impacting the future calculation of depreciation and amortization. Long-lived refining assets are also evaluated for potential impairment by identifying whether indicators of impairment exist and, if so, assessing whether the long-lived assets are recoverable from estimated future undiscounted cash flows. The actual amount of impairment loss, if any, to be recorded is equal to the amount by which a long-lived asset’s carrying value exceeds its fair value. Estimates of future cash flows and fair values of assets require subjective assumptions with regard to future operating results and actual results could differ from those estimates.

The refining assets require regular major maintenance and repairs which are commonly referred to as “turnarounds”. Catalysts used in certain refinery processes also require routine “change-outs”. The required frequency of the maintenance varies by asset type and by catalyst, but generally is every two to five years. The costs of turnarounds and change-outs are recorded as capital costs and are amortized over the period to the next scheduled turnaround or change-out.

Furniture, equipment and leaseholds

Furniture and equipment are recorded at cost and are being depreciated on a declining balance basis at rates of 20 percent to 30 percent per year. Leaseholds are amortized over the lease term.

Investment in Petrolifera Petroleum Limited

The investment in Petrolifera Petroleum Limited (“Petrolifera”) is accounted for on an equity basis, whereby the carrying value reflects the company’s investment, at the lower of cost and fair value, and the company’s equity interest share of its accumulated income. Any permanent decline in value would be charged to earnings.

Income taxes

The company follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributed to differences between the amounts reported in the financial statements and their respective tax bases, using substantively enacted income tax rates. The effect of a change in income tax rates on future income tax assets and liabilities is recognized in income in the period that the change occurs. Future tax assets recognized are assessed by management at each balance sheet date for impairment.

An impairment is recognized when management assesses that it’s not more likely than not that the asset will be recovered.

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is annually assessed for impairment. Goodwill and all other assets and liabilities have been allocated to the company’s segments, referred to as reporting units. To assess impairment, the fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit’s assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit’s goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount.

Asset retirement obligations

The company recognizes an asset retirement obligation liability for abandoning petroleum, natural gas and bitumen wells, related facilities, compressors and gas plants, removal of equipment from leased acreage and returning such land to its original condition by estimating and recording the fair value of each asset retirement obligation arising in the period a well or related asset is drilled, constructed or acquired. This fair value is estimated using the present value of the estimated future cash outflows to abandon the asset at the company’s credit adjusted risk-free interest rate and includes estimates for inflation. The obligation is reviewed regularly by management based upon current regulations, costs, technologies and industry standards. The discounted obligation is initially capitalized as part of the carrying amount of the related petroleum, natural gas or bitumen property and a corresponding liability is recognized. The liability is accreted against income until it is settled or the property is sold and is included as a component of depletion and depreciation expense. The amount of the capitalized retirement obligation is depleted and depreciated on the same basis as the other capitalized

petroleum or natural gas property costs. Actual restoration expenditures are charged to the accumulated obligation as incurred and costs for properties disposed are removed.

Employee future benefits

The costs of the defined benefit pension plan are actuarially determined using the projected benefit method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. For the purpose of calculating the expected return on plan assets, those assets are valued at a market-related value. The cost of the company's portion of the defined contribution plan is expensed as incurred.

Convertible Debentures

The Convertible Debentures have been classified as long term debt and equity at their fair value at the date of issue. The fair value of the liability component has been determined based on the company's incremental borrowing rate for debt with similar terms. The amount of the equity component has been determined as a residual after deducting the amount of the liability component from the face value of the debentures.

Share award plan for non-employee directors

Obligations for payments in cash or common shares under the company's share award plan for non-employee directors are accrued as stock-based compensation expense and liabilities over the vesting period. Fluctuations in the price of the company's common shares change the accrued compensation expense and are recognized over the remaining vesting period.

Flow-through shares

The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. Accordingly, share capital is reduced and the future income tax liability is increased by the tax benefits related to the expenditures at the time they are renounced.

Foreign currency translation

The company has assessed the operations of MRCI to be self-sustaining. Assets and liabilities of self-sustaining foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date and revenues and expenses are translated at the average monthly rates of exchange during the periods. Gains or losses on translation of self-sustaining foreign operations are included in accumulated other comprehensive income (loss) in shareholders' equity. Transaction-based foreign exchange gains and losses are included in earnings.

Financial instruments

Financial instruments include cash and cash equivalents, restricted cash, accounts receivable, amounts due from Petrolifera, the Revolving Credit Facilities, accounts payable, the Convertible Debentures, the Second Lien Senior Notes and the cross-currency and interest rate swaps. All carrying values of financial instruments approximate fair value with the exception of the Convertible Debentures and Second Lien Senior Notes, which are initially recognized at fair value and are subsequently accounted for under the amortized cost method. Accretion of the discount on the Convertible Debentures and Second Lien Senior Notes is a finance cost.

The company has classified all of its financial instruments, with the exception of the Second Lien Senior Notes, the Convertible Debentures and the Revolving Credit Facilities, as Held for Trading, which requires measurement on the balance sheet at fair value with any changes in fair value recorded in earnings. This classification has been chosen due to the nature of the company's financial instruments, which, except for the Second Lien Senior Notes, the Convertible Debentures and Revolving Credit Facilities are of a short-term nature such that there are no material differences between the carrying values and the fair values. Transaction costs related to financial instruments classified as Held for Trading are recorded in earnings. Transaction costs relating to the Convertible Debentures and Second Lien Senior Notes are amortized against earnings over the term of the instrument using the effective interest rate method.

Any amounts that would be drawn on the Revolving Credit Facilities would be classified as "other financial liabilities" on the consolidated balance sheet because the fair value of such liability would closely approximate its carrying value due to the revolving nature of such debt. Transaction costs related to the Revolving Credit Facilities were being amortized over their term.

Joint venture operations

A part of the company's activities is conducted with others, and these consolidated financial statements reflect only the company's proportionate interest in such activities.

Revenue recognition

Petroleum, natural gas and refined product sales are recognized as revenue at the time the respective commodities are delivered to purchasers.

Unrealized gains and losses from the company's natural gas and crude oil commodity price risk management activities are recorded as revenue based on mark-to-market calculations.

Prior to attaining commercial operations status, revenues on bitumen sales from the company's oil sands projects are credited to those project costs. Upon attaining commercial operations, oil sands revenues are recognized as bitumen is delivered to purchasers.

Natural gas, bitumen, diluent and other products and services may be purchased and sold between the company's subsidiaries. On consolidation, these intercompany amounts are eliminated.

Stock-based compensation

The fair value of each stock option granted is estimated on the date of grant using the Black-Scholes option pricing model. The amount is expensed or capitalized and credited to contributed surplus over the vesting period. Upon exercise of the options, the exercise proceeds together with amounts credited to contributed surplus, are credited to share capital.

Segment reporting

The company has changed its segmentation in 2008 to better reflect the organization of its business by combining the former Canadian administrative segment with the Canadian oil and gas segment. In Canada, the company is in the business of exploring for and producing crude oil, natural gas and bitumen. In the U.S., the company is in the business of refining and marketing petroleum products. Comparative figures have been reclassified.

The above have been defined as the operating segments of the company because they (a) produce products which are sufficiently differentiated from each other so as to be separately identifiable; (b) are those for which operating results are regularly reviewed by the company's chief operating decision maker to make decisions about resources to be allocated to each segment and to assess its performance; and (c) are those for which discrete financial information is available.

Segment accounting policies are the same as those described in this summary of significant accounting policies. Transfers of assets between segments are recorded at carrying value.

Measurement uncertainty

The timely preparation of the consolidated financial statements in conformity with Canadian GAAP requires that management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Income taxes are subject to re-assessment by tax authorities. Estimates of the stage of completion of capital projects at the financial statement date affect the calculation of additions to property and equipment and the related accrued liability.

Amounts recorded for depreciation, depletion and accretion, asset retirement costs and obligations, amounts used for ceiling test and impairment calculations and amounts used in the determination of future taxes are based on estimates of petroleum, natural gas and bitumen reserves and future costs required to develop those reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs and the related future cash flows are subject to measurement uncertainty.

Amounts recorded for stock-based compensation expense are based on the historical volatility of the company's share price, which may not be indicative of future volatility. Accordingly, those amounts are subject to measurement uncertainty.

Credit risk

The company generally extends unsecured credit to customers and therefore, the collection of accounts receivable may be affected by changes in economics or other conditions. Management believes this risk is mitigated by the size and reputation of the companies to which credit has been extended. The company has not historically experienced any material credit loss in the collection of accounts receivable.

Commodity and financial risk management

The company periodically enters into contracts to fix the price of a portion of its petroleum and natural gas sales to reduce the exposure to commodity price fluctuations. Occasionally these contracts are denominated in Canadian dollars to mitigate foreign exchange risks.

To help mitigate some of the foreign currency and interest rate risk associated with its US-denominated Senior Notes, the company from time to time enters into cross-currency and interest rate swaps.

Unless any of these transactions are designated as “hedged” for accounting purposes, they would be marked to market for financial statement reporting purposes.

Per share amounts

Basic per share amounts are calculated using the weighted average number of common shares outstanding for the year. The company follows the treasury stock method to calculate diluted per share amounts. The treasury stock method assumes that any proceeds from the exercise of in-the-money stock options and other dilutive instruments plus the amount of stock-based compensation not yet recognized would be used to purchase common shares at the average market price during the period.

3. New Accounting Standards

As of January 1, 2008, the company adopted two new CICA Handbook requirements, section 3862, “Financial Instruments – Disclosures” and section 3863, “Financial Instruments – Presentation,” which replaced section 3861. The new standards require disclosure of the significance of financial instruments to an entity’s financial statements, the risks associated with the financial instruments and how those risks are managed.

As of January 1, 2008, the company adopted CICA Handbook section 1535, “Capital Disclosures” which requires entities to disclose their objectives, policies and processes for managing capital and, in addition, whether the entity has complied with any externally imposed capital requirements.

In February 2008, the CICA issued Section 3064, “Goodwill and Intangible Assets,” replacing Section 3062, “Goodwill and Other Intangible Assets” and Section 3450, “Research and Development Costs.” Various changes have been made to other sections of the CICA Handbook for consistency purposes. The new Sections will be applicable to financial statements relating to fiscal years beginning on or after October 1, 2008. Accordingly, the company will adopt the new standards for its fiscal year beginning January 1, 2009. Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062 and, therefore, are not anticipated to have a significant impact on the company’s financial statements.

Over the next two years the CICA will adopt its new strategic plan for the direction of accounting standards in Canada, which was ratified in January 2006. As part of the plan, Canadian GAAP for public companies will converge with International Financial Reporting Standards (“IFRS”) with an effective date of January 1, 2011. The company continues to monitor and assess the impact of the convergence of Canadian GAAP with IFRS.

4. Financial Instruments And Capital Risk Management

Financial Instruments

The financial instruments standard (CICA Section 3855) establishes the recognition and measurement criteria for financial assets, financial liabilities and derivatives. All financial instruments are required to be measured at fair value on initial recognition of the instrument, except for certain related party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as “held-for-trading,” “available-for-sale,” “held-to-maturity,” “loans and receivables,” or “other financial liabilities” as defined by the accounting standard.

Financial assets and financial liabilities “held-for-trading” are measured at fair value with changes in those fair values recognized in net earnings. Financial assets “available-for-sale” are measured at fair value, with changes in those fair values recognized in OCI. Financial assets “held-to-maturity,” “loans and receivables” and “other financial liabilities” are measured at amortized cost using the effective interest rate method of amortization.

The company has classified all of its financial instruments, with the exception of the Second Lien Senior Notes, the Convertible Debentures and the Revolving Credit Facilities, as Held for Trading. This classification has been chosen due to the nature of the company’s financial instruments, which, except for the Second Lien Senior Notes, the Convertible Debentures and Revolving Credit Facilities, are of a short-term nature such that there are no material differences between the carrying values and the fair values.

The Second Lien Senior Notes and the Convertible Debentures have been classified as “other financial liabilities” and are accounted for on the amortized cost method, with transaction costs being amortized over the life of the instrument using the effective interest rate method.

Any amounts drawn on the Revolving Credit Facilities would have been classified as “other financial liabilities” on the consolidated balance sheet. The fair value of any such liability would have closely approximated carrying value due to its revolving nature. Transaction costs related to the Revolving Credit Facilities were being amortized over their term.

Capital Risk Management

The company is exposed to financial risks on a range of financial instruments including its cash, accounts receivable and payable, amounts due from Petrolifera, its Revolving Credit Facilities, the Convertible Debentures and the Second Lien Senior Notes.

The company is also exposed to risks in the way it finances its capital requirements. The company manages these financial and capital structure risks

by operating in a manner that minimizes its exposures to volatility of the company’s financial performance. These risks affecting the company are discussed below.

(a) Credit risk

Credit risk is the risk that a contracting entity will not fulfill its obligations under a financial instrument and cause a financial loss to the company. To help manage this risk, the company has a policy for establishing credit limits, requiring collateral before extending credit to customers where appropriate and monitoring outstanding accounts receivable. The company’s financial assets subject to credit risk arise from the sale of crude oil, bitumen, natural gas and refined products to a number of large integrated oil companies and product retailers and are subject to normal industry credit risks. The fair value of accounts receivable and accounts payable are represented by their carrying values due to the relatively short periods to maturity of these instruments. The maximum exposure to credit risk is represented by the carrying amount on the consolidated balance sheet. The company regularly assesses its financial assets for impairment losses. There are no material financial assets that the company considers past due or any allowances for uncollectible accounts.

The majority of the company’s upstream revenues are composed of bitumen sales. Substantially all of the company’s sales were made to three customers in 2008.

b) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The company is exposed to market risk as a result of potential changes in the market prices of its crude oil, bitumen, natural gas and refined product sales volumes.

A portion of this risk is mitigated by Connacher’s integrated business model. The cost of purchasing natural gas for use in its oil sands and refinery operations is offset by the company’s monthly conventional natural gas sales; and the selling price of the company’s dilbit sales largely equates to the purchase price of heavy crude oil required for processing at its refinery. Petroleum commodity futures contracts, price swaps and collars may be utilized to reduce exposure to price fluctuations associated with the sales of additional natural gas and crude oil sales volumes and for the sale of refined products.

As part of the company’s risk management strategy, a natural gas costless collar contract was put in place effective for the period April 1 to

October 31, 2008. The collar had a floor price of US\$7.50/mmbtu and a ceiling price of US\$10.05/mmbtu on a notional volume of 5,000 mmbtu per day of natural gas sales. The intent of this natural gas pricing collar was not to speculate on future natural gas prices, but rather to protect the downside risk to the company’s cash flow and the lending value of its assets on a portion of natural gas sales volumes notionally in excess of those required for consumption at Pod One. The risk in implementing the collar was that future natural gas prices could escalate beyond the ceiling price, limiting the company’s natural gas revenue. In 2008, reported Upstream Revenues decreased by \$831,000 as a result of carrying this contract (approximately \$0.18 per mcf).

In November 2008 Connacher entered into a foreign exchange collar which sets a floor of CAD \$1.1925 per US \$1.00 and a ceiling of CAD \$1.3000 per US \$1.00 on a notional amount of US \$10,000,000 of production revenue per month throughout 2009. At December 31, 2008 the fair value of this contract was an asset of \$1.8 million which is recorded in accounts receivable on the consolidated balance sheet. The corresponding gain is included in the net foreign exchange loss in the consolidated statement of operations. A \$0.01 change on the USD/CAD exchange rate would result in a \$700,000 change in the fair value of the collar.

(c) Interest rate risk

Interest rate risk refers to the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The company’s Second Lien Senior Notes and Convertible Debentures have fixed interest rate obligations and, therefore, are not subject to changes in variable interest rates.

(d) Currency risk

Currency risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in foreign exchange rates.

As Connacher incurs the majority of its expenditures in Canadian dollars, its exposure to fluctuations in the US/Canadian dollar exchange rate primarily relates to pricing of its sales of crude oil and bitumen (which are generally priced by reference to US dollars but settled in Canadian dollars) and on the translation of its US refining operating results and its US dollar denominated Second Lien Senior Notes to Canadian dollars for financial statement reporting purposes.

In order to mitigate half of the foreign exchange exposure on the Second Lien Senior Notes, the company entered into cross currency and interest rate swaps to fix one half of the Second Lien Senior Notes' principal and interest payments in Canadian dollars. In the fourth quarter of 2008 the company monetized the cross-currency and interest rate swaps by unwinding them and realized net cash proceeds of \$89.1 million, of which \$97.6 million was recorded as a realized foreign exchange gain, \$2.6 million was recorded as a finance charge and \$5.9 million was capitalized to property and equipment.

Relative to the company's U.S. dollar cash balances, crude oil and bitumen revenue receivables and Second Lien Senior Notes, a \$0.01 change in the Canadian dollar exchange rate would have resulted in a \$5.7 million change in net earnings for 2008.

(e) Liquidity risk

Liquidity risk is the risk that the company will not have sufficient funds to repay its debts and fulfill its financial obligations.

To manage this risk, the company follows a conservative financing philosophy, pre-funds major development projects, monitors expenditures against pre-approved budgets to control costs, regularly monitors its operating cash flow, working capital and bank balances against its business plan, usually maintains accessible revolving banking lines of credit and maintains prudent insurance programs to minimize exposure to insurable losses.

Additionally, the long term nature of the company's debt repayment obligations is aligned to the long term nature of its assets. The Convertible Debentures do not mature until June 30, 2012, unless converted to common shares earlier, and principal repayments are not required on the Second Lien Senior Notes until their maturity date of December 15, 2015. This affords Connacher the opportunity to deploy its conventional, oil sands, and refinery cash flow to fund the development of further expansion projects over the next several years without having to make principal payments or raise new capital unless expenditures exceed cash flow and credit capacity.

The company was in compliance with all of its financial covenants at December 31, 2008.

The change in carrying value of long-term debt at December 31, 2008 (\$779 million) from December 31, 2007 (\$664 million) is primarily due to the change in the Canadian: US exchange rate in converting the US dollar-denominated Second Lien Senior Notes to Canadian dollars and accretion of the debt discount of approximately \$5.5 million.

At December 31, 2008 the fair values of the Convertible Debentures and Second Lien Senior Notes were approximately \$45 million and \$287 million, respectively, based on their quoted market prices.

The company's term debt is repayable as follows:

- Convertible Debentures – June 30, 2012 in the amount of \$100 million unless converted into common shares prior thereto; and
- Second Lien Senior Notes – December 15, 2015 in the amount of US \$592 million.

Connacher's investment in Petrolifera also provides liquidity. Trading on the TSX, Connacher's 13.1 million shares held in Petrolifera may be sold as they have not been collateralized. Although it is not Connacher's intention to sell these shares in the foreseeable future, the shareholding provides Connacher an additional margin of financial safety.

(f) Capital risks

Connacher's objectives in managing its cash, debt and equity, its capital structure and its future capital requirements are to safeguard its ability to meet its financial obligations, to maintain a flexible capital structure that allows multiple financing options when a financing need arises and to optimize its use of short-term and long-term debt and equity at an appropriate level of risk.

The company manages its capital structure and follows a financial strategy that considers economic and industry conditions, the risk characteristics of its underlying assets and its growth opportunities. It strives to continuously improve its credit rating and reduce its cost of capital. Connacher monitors its capital using a number of financial ratios and industry metrics to ensure its objectives are being met and to ensure continued compliance with its debt covenants.

Connacher's current capital structure and certain financial ratios are noted below.

(\$000)	As at December 31, 2008	As at December 31, 2007
Long term debt ⁽¹⁾	\$778,732	\$664,462
Shareholders' equity		
Share capital, contributed surplus and equity component	437,899	444,086
Accumulated other comprehensive income (loss)	7,802	(13,636)
Retained earnings	23,386	49,989
Total	\$1,247,819	\$1,144,901
Debt to book capitalization ⁽²⁾	62%	58%
Debt to market capitalization ⁽³⁾	81%	44%

(1) Long-term debt is stated at its carrying value, which is net of transaction costs and the Convertible Debentures' equity component value.

(2) Calculated as long-term debt divided by the book value of shareholders' equity plus long-term debt.

(3) Calculated as long-term debt divided by the period end market value of shareholders' equity plus long-term debt.

Connacher currently has a high ratio of debt to capitalization and its debt service costs are high relative to cash flow. This is due to pre-funding of the full cost of Algar, the company's second oil sands project, in 2007, by issuing US\$600 million of Second Lien Senior Notes, a portion of which was used to repay indebtedness previously incurred for Pod One. As at December 31, 2008, the company's net debt (long-term debt, net of cash on hand) was \$555 million, its net debt to book capitalization was 44 percent and its net debt to market capitalization was 57 percent.

5. Inventories

Inventories at December 31 consist of the following:

(\$000)	2008	2007
Crude oil	\$3,433	\$2,258
Other raw materials and unfinished products ⁽¹⁾	1,762	1,501
Refined products ⁽²⁾	18,901	11,183
Process chemicals ⁽³⁾	8,110	1,036
Repairs and maintenance supplies and other ⁽⁴⁾	3,787	2,401
	\$35,993	\$18,379

(1) Other raw materials and unfinished products include feedstocks and blendstocks, other than crude oil. The inventory carrying value includes the costs of the raw materials and transportation.

(2) Refined products include gasoline, jet fuels, diesels, asphalts, liquid petroleum gases and residual fuels. The inventory carrying value includes the cost of raw materials including transportation and direct production costs.

(3) Process chemicals include catalysts, additives and other chemicals. The inventory carrying value includes the cost of the purchased chemicals and related freight.

(4) Repair and maintenance supplies for refining and oil sands operations.

The amount of inventory recognized in downstream-crude oil purchases during 2008 was \$349.8 million (2007 – \$237.1 million).

As a consequence of decreased crude oil and asphalt prices during the fourth quarter of 2008, the company wrote down its purchased crude oil, asphalt and other refined products in inventories in the amount of \$9 million at December 31, 2008 (2007 – \$562,000), which is included in downstream-crude oil purchases and operating costs.

6. Investment In Petrolifera Petroleum Limited (“Petrolifera”)

Changes to the investment in Petrolifera are as follows:

(\$000)	
Investment in Petrolifera, December 31, 2006	\$21,597
Equity in Petrolifera’s 2007 earnings	6,953
Exercise of warrants – purchase of additional common shares	5,143
Dilution gain resulting from issuance of Petrolifera shares in 2007	1,917
Investment in Petrolifera, December 31, 2007	35,610
Equity in Petrolifera’s 2008 earnings	3,085
Dilution gain resulting from issuance of Petrolifera shares in 2008	7,964
Investment in Petrolifera, December 31, 2008	\$46,659

Dilution gains have been recognized whenever changes have occurred in the company’s equity interest in Petrolifera, most notably relative to Petrolifera’s \$7 million private placement financing completed in March 2005 when Connacher’s equity interest holding was reduced from 61 percent to 40 percent, resulting in a dilution gain of \$3 million. Although Connacher participated in Petrolifera’s \$21.3 million initial public offering in November 2005 by investing \$6 million, Connacher’s equity investment interest was reduced to 35 percent and a further dilution gain of \$1.5 million was then recognized.

In April 2007, the company exercised warrants to purchase 1.7 million additional common shares in Petrolifera for total consideration of \$5.1 million. As a result, the company increased its equity interest. Because other Petrolifera shareholders similarly exercised their warrants to purchase additional common shares in Petrolifera on identical terms, the company’s interest decreased to 26 percent, resulting in a dilution gain of \$1.9 million.

In June 2008, Petrolifera issued an additional 4.4 million common shares to raise \$40 million. Connacher did not subscribe for any of these shares. Consequently, Connacher’s equity interest in Petrolifera was reduced from 26 percent to 24 percent resulting in a dilution gain of \$8 million, which was recognized by Connacher in the second quarter of 2008.

In consideration for the assistance provided to Petrolifera in securing two Peruvian licenses for exploratory lands and for the provision of financial guarantees respecting Petrolifera’s annual work commitments in the two licensed blocks in 2005, Connacher was granted a five-year option to acquire 200,000 common shares at \$0.50 per share and was granted a 10 percent carried working interest (“CWI”) through the drilling of the first well on each block. Petrolifera has the right of first purchase of this CWI should Connacher elect to sell it at some future date. The CWI is convertible at the holder’s election into a two percent gross overriding royalty on each license after the drilling of the first well on each block.

Under the terms of an Administrative Services Agreement dated January 1, 2008 with Petrolifera, Connacher provides certain management and general and administrative services to Petrolifera. The fee for this service is \$15,000 per month. Connacher is also guarantor for Petrolifera in Peru and operator of record on behalf of Petrolifera in Colombia for which Connacher is indemnified by Petrolifera. Petrolifera paid Connacher \$180,000 in 2008 (2007 – \$200,000) under the Administrative Services Agreement.

7. Property And Equipment

(\$000)	Cost	Accumulated Depletion, Depreciation and Amortization	Net Book Value
2008			
Oil sands, crude oil and natural gas properties and equipment	\$1,004,891	\$112,013	\$892,878
Refining assets	99,823	13,620	86,203
Furniture, equipment and leaseholds	9,999	4,026	5,973
	\$1,114,713	\$129,659	\$985,054

2007			
Oil sands, crude oil and natural gas properties and Refining assets	\$678,176	\$67,499	\$610,677
Furniture, equipment and leaseholds	59,192	5,182	54,010
	9,219	2,484	6,735
	\$746,587	\$75,165	\$671,422

In 2008, the company capitalized \$5.2 million (2007 – \$3.4 million) of general and administrative expenses, stock-based compensation costs of \$1.5 million (2007 – \$2.2 million), and \$47.1 million (2007 – \$24.6 million) of interest and financing costs related to oil sands and conventional petroleum and natural gas activities.

Depletion, depreciation and accretion expense includes a charge of \$1.7 million (2007 – \$1.6 million) to accrete the company's estimated asset retirement obligations (Note 11).

The ceiling test as at December 31, 2008 excludes \$14.2 million (2007 – \$14.7 million) of undeveloped land and \$297 million (2007 – \$413 million) of major development project costs, principally related to oil sands assets in the pre-production stage, which have been separately evaluated by management for impairment. Based on the ceiling test and other assessments, no impairment has been recorded at December 31, 2008.

Connacher's oil sands, crude and natural gas reserves were evaluated by qualified independent evaluators as at December 31, 2008 in a report dated February 4, 2009. The evaluation was conducted in accordance with the Canadian Securities Administrators' National Instrument 51-101, using the following base price assumptions adjusted for the company's product quality and transportation differentials:

	Bitumen Wellhead Current (\$CDN/bbl)	WTI @ Cushing (\$US/bbl)	Alberta Spot (\$CDN/mmbtu)
2009	\$23.10	\$57.50	\$7.34
2010	31.33	68.00	7.70
2011	42.25	74.00	8.10
2012	50.06	85.00	8.46
2013	54.66	92.01	8.70
	Approximately 2% thereafter	Approximately 2% thereafter	Approximately 2% thereafter

8. Deferred Costs

Deferred costs are composed of the following:

(\$000's)	December 31, 2008	December 31, 2007
Deferred capital costs related to refinery	\$–	\$1,835
Deferred financing costs related to Revolving Credit Facilities	–	3,752
	\$–	\$5,587

The unamortized costs of the Revolving Credit Facility were expensed in 2008. (See Note 10.)

9. Income Taxes

The income tax recovery of \$5.3 million in 2008 includes a current income tax recovery of \$12.9 million, principally related to US refinery operations and a future income tax provision of \$7.6 million reflecting the movement in tax pools during the year.

The following table reconciles income taxes calculated at the Canadian statutory rate with recorded income taxes:

Years Ended December 31 (\$000)	2008	2007
Earnings (loss) before income taxes	\$(31,914)	\$53,966
Canadian statutory rate	29.8%	32.7%
Expected income taxes (recovery)	(9,510)	17,647
Impact of reduction in Canadian tax rates and other	1,846	(5,385)
Foreign taxes (recovery)	(2,130)	2,488
Capital taxes	1,535	1,896
Non taxable portion of foreign exchange losses (gains)	3,233	(4,100)
Equity income and dilution gain	(1,644)	(1,523)
Non deductible stock-based compensation costs	1,359	1,982
Provision (recovery) for income taxes	\$(5,311)	\$13,005

The company had the following future tax assets (liabilities) relating to temporary differences.

As at December 31 (\$000)	2008	2007
Book value in excess of tax basis of property, plant and equipment	\$(101,008)	\$(56,725)
Non-capital losses carried forward	23,055	18,647
Foreign exchange loss (gain) on debt	11,224	(532)
Partnership deferral	–	(6,360)
Investment in Petrolifera	(4,153)	(2,850)
Deferred capital costs	(231)	(723)
Financing and share issue costs	7,125	3,998
Asset retirement obligation	6,620	6,164
Other	(928)	1,563
Net future income tax liability	\$(58,296)	\$(36,818)

At December 31, 2008 the company had approximately \$89 million of non-capital losses which expire over time to 2028, \$551 million of deductible resource pools and \$26 million of deductible financing costs. The future income tax benefit of these have been recognized at December 31, 2008. Additionally, the company had \$167 million of capital losses available to reduce capital gains in future. These capital losses have no expiry and their future income tax benefit has not been recognized due to uncertainty of their realization at December 31, 2008.

10. Indebtedness

The company had the following long-term debt outstanding, as at December 31

(\$000)	2008	2007
Second Lien Senior Notes	\$694,086	\$570,594

Cross-currency and interest rate swaps liability	–	12,735
Convertible Debentures	84,646	81,133
Total	778,732	664,462
Less current portion of long-term debt	–	–
Long-term portion	\$778,732	\$664,462

Senior Notes

On December 3, 2007 the company issued US \$600 million of Senior Notes (“Senior Second Lien Secured Notes”) at an issue price of 98.657 for net proceeds of US \$575.4 million after fees and expenses. A portion of the proceeds was used to repay the US \$180 million Oil Sands Term Loan then outstanding and to fund a one-year interest reserve account in the amount of US \$63.6 million. The remainder of the proceeds are to be used to fund the construction of Algar, the company’s second oil sands project. The Second Lien Senior Notes bear interest at a rate of 10.25% payable semi-annually on June 15 and December 15. No principal payments are due until the maturity date of December 15, 2015. The Second Lien Senior Notes are secured by a second lien covering substantially all of the company’s assets with the exception of its investment in Petrolifera.

The company may redeem some or all of the Second Lien Senior Notes at their principal amount plus a make whole premium if such redemption occurs prior to December 15, 2011. After December 15, 2011, the Second Lien Senior Notes may be redeemed at redemption prices ranging from 105.125 percent reducing to 100 percent on December 15, 2013 and thereafter.

The company may redeem up to 35% of the of the Second Lien Senior Notes prior to December 15, 2010 at a redemption price of 110.25 percent of the principal amount plus accrued interest with the proceeds of certain equity offerings provided that at least 65% of the aggregate principal amount of the Second Lien Senior Notes remains outstanding on existing terms. Upon a change of control of the company, the holders of the Second Lien Senior Notes may require Connacher to purchase the Second Lien Senior Notes at redemption prices noted above, with a minimum price of 101 percent of the principal amount to be repurchased.

In the fourth quarter of 2008, the company repurchased US \$8 million face value of Second Lien Senior Notes in the market at a discount, cancelled the notes, and realized a gain of \$2.8 million.

A portion of the interest on the Second Lien Senior Notes attributed to the company’s first oil sands project (“Pod One”), has been expensed since the commencement of its commercial operations (March 1, 2008). Interest on the portion of the loan which is used to fund the construction of Algar is being capitalized.

At December 31, 2008, the fair value of the Second Lien Senior Notes was approximately \$287 million. This amount was determined by reference to the quoted market price for the company’s Second Lien Senior Notes.

Cross-Currency and Interest Rate Swaps

To partially mitigate the foreign exchange risk associated with its Second Lien Senior Notes in 2007, the company entered into cross currency and interest rate swaps to fix a portion of the Second Lien Senior Notes’ US dollar denominated principal and interest payments in Canadian dollars. At December 31, 2007, the fair value of these swaps was a liability of \$12.7 million, which was included with long-term debt in the consolidated balance sheet. An unrealized foreign exchange loss of \$9.6 million related to the cross currency swap was recorded in income in 2007 and \$3.1 million related to the interest rate swap was capitalized to property and equipment. The unrealized 2007 foreign exchange loss was offset by a \$9.7 million unrealized gain on translating the Second Lien Senior Notes and the interest rate swap at December 31, 2007.

In the fourth quarter of 2008 the company monetized the cross-currency and interest rate swaps by unwinding them and realized cash proceeds of \$89.1 million, of which \$97.6 million was recorded as a realized foreign exchange gain, \$2.6 million was recorded as a finance charge and \$5.9 million was capitalized to property and equipment.

Convertible Debentures

On May 25, 2007 Connacher issued senior unsecured subordinated Convertible Debentures with a face value of \$100,050,000. The Convertible Debentures mature June 30, 2012 unless converted prior to that date and bear interest at an annual rate of 4.75 percent payable semiannually on June 30 and December 31. The Convertible Debentures are convertible at any time into common shares at the option of the holder at a conversion price of \$5.00 per share.

The Convertible Debentures are redeemable on or after June 30, 2010 by the company, in whole or in part at a redemption price equal to 100 percent of the principal amount of the Convertible Debentures to be redeemed plus accrued and unpaid interest provided that the market price of the company's common shares is at least 120 percent of the conversion price of the Convertible Debentures.

The conversion feature of the Convertible Debentures has been accounted for as a separate component of equity in the amount of \$16,823,000. The remainder of the net proceeds of the Convertible Debentures of \$79,187,000 was recorded as long-term debt, which will be accreted up to the face value of \$100,050,000 over the five-year term of the Convertible Debentures. Accretion and interest paid are recorded as finance charges on the consolidated statement of operations. If the Convertible Debentures are converted to common shares, the value of the conversion feature will be reclassified to share capital along with the principal amounts converted.

At December 31, 2008, the fair value of the Convertible Debentures was \$45 million (December 31, 2007 – \$96.5 million). This amount was determined by reference to the quoted market price for the Convertible Debenture.

Revolving Credit Facilities

At December 31, 2008 the company had available revolving lines of credit in the amounts of CAD \$150 million and US \$50 million. No amounts were drawn under the revolving credit facilities at December 31, 2008 other than as security for letters of credit in the amount of \$6 million. Subsequent to December 31, 2008, the company terminated the Revolving Credit Facilities. The unamortized costs of establishing this facility (\$3.75 million) were expensed in 2008.

Principal repayments due

Principal repayments for all the aforementioned loans are due as follows: (\$000)

	2008	2007
2009	\$–	\$–
2010	–	–
2011	–	–
2012	100,050	100,050
2013	–	–
Thereafter	721,056	612,735
	\$821,106	\$712,785

11. Asset Retirement Obligations

The following table reconciles the beginning and ending aggregate carrying amount of the obligation associated with the company's retirement of its upstream crude oil, natural gas and oil sands properties and facilities.

Year ended December 31 (\$000)	2008	2007
Asset retirement obligations, beginning of year	\$24,365	\$7,322
Liabilities incurred	1,496	8,277
Liabilities settled	(209)	(311)
Change in estimated future cash flows	(960)	7,503
Accretion expense	1,704	1,574
Asset retirement obligations, end of year	\$26,396	\$24,365

At December 31, 2008 the estimated total undiscounted amount required to settle the asset retirement obligations was \$47.3 million (2007 – \$44.4 million). These obligations are expected to be settled over the useful lives of the underlying assets, which currently extend up to 20 years into the future. This amount has been discounted using a credit-adjusted risk-free rate of interest and after provision for inflation.

The company has not recorded an asset retirement obligation for the Montana refinery as it is currently the company'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.

12. Employee Future Benefits

The company maintains the following retirement/savings plans for its employees: a defined benefit pension plan and a defined contribution savings plan for its US-based employees and a defined contribution savings plan for its Canadian employees.

(a) The defined benefit pension plan

The company's US subsidiary, MRCI, maintains a non-contributory defined benefit retirement plan (the "Defined Benefit Plan") covering MRCI's employees. MRCI's policy is to make regular contributions in accordance with the funding requirements of the United States Employee Retirement Income Security Act of 1974 as determined by regular actuarial valuations. The company's pension obligation is based on the employees' years of service and compensation, effective from, and after, March 31, 2006, the date that Connacher acquired the refining assets and hired the refinery personnel. In 2007, MRCI fully funded the Defined Benefit Plan's cost for 2006 and 2007.

MRCI is responsible for administering the Defined Benefit Plan and has retained the services of an independent and professional investment manager, as fund manager, for the related investment portfolio. Among the factors considered in developing the investment policy are the Defined Benefit Plan's primary investment goal, rate of return objective, investment risk, investment time horizon, role of asset classes and asset allocation.

Details of this Defined Benefit Plan for the years ended December 31, 2007 and 2008 are based on actuarial valuations prepared as at those dates.

For the years ended December 31 (\$000)	2008	2007
Total expense for the Plan	\$730	\$447

Defined Benefit Plan Obligation

Accrued Defined Benefit Plan Obligation, Beginning of the Year	\$ 617	\$ 388
Current service cost	723	470
Interest cost	62	21
Actuarial (gain) loss	(52)	(140)
Benefits paid	(63)	(24)
Foreign exchange (gain) loss	183	(98)
Accrued Defined Benefit Plan Obligation, End of Year	\$1,470	\$ 617

Defined Benefit Plan Assets

Fair Value of Defined Benefit Plan Assets, Beginning of Year	\$757	\$ –
Actual return on plan assets	(192)	43
Employer contributions	–	781
Benefits paid	(63)	(24)
Foreign exchange gain (loss)	138	(43)
Fair Value of Defined Benefit Plan Assets, End of Year	\$640	\$ 757

Accrued Benefit Asset (Liability)

Funded Status – Defined Benefit Plan Assets greater (less) than Defined Benefit Plan	\$(830)	\$140
Unamortized net actuarial (gain) loss	38	(140)
Accrued Defined Benefit Plan Asset (Liability)	\$(792)	\$–

The weighted average assumptions used to determine benefit obligations and periodic expense are as follows:

Discount Rate	5.75%	5.75%
Expected Long-Term Rate of Return on Plan Assets:	7.0%	7.0%
Rate of compensation increase	3.0%	3.0%

The periodic expense for benefits is as follows:

Current Service Cost	\$723	\$470
Interest Cost	62	21
Actual Return on Defined Benefit Plan Assets	192	(43)
Difference between actual and expected return on plan assets	(247)	(1)
Net Defined Benefit Plan Expense	\$730	\$447

The average remaining service period of the active employees covered by the Defined Benefit Plan is 14.54 years.

The Company's pension plan asset allocation is as follows:

Asset Category	% of Plan Assets at December 31	
	2008	2007
Equity securities	59%	57%
Debt securities	37%	39%
Cash and cash equivalents	4%	4%
Total	100%	100%

The expected rate of return on plan assets is based on historical and projected rates of return for each asset class in the plan investment portfolio. The objective of asset allocation policy is to manage the funded status of the plan at an appropriate level of risk, giving consideration to the security of the assets and the potential volatility of market returns and the resulting effect on both contribution requirements and pension expense. The long-term return is expected to achieve or exceed the return from a composite benchmark comprised of passive investments in appropriate market indices.

The asset allocation structure is subject to diversification requirements and constraints which reduce risk by limiting exposure to individual equity investment, credit rating categories and foreign currency exposure.

(b) The MRCI defined contribution savings plan for United States employees

MRCI also maintains defined contribution (US tax code "401(k)"), savings plans that cover all of its employees. MRCI's contributions are based on employees' compensation and partially match employee contributions. In 2008, MRCI contributed \$343,000 (2007 – \$345,000) to this plan, to satisfy, in full, its obligation under this plan.

(c) The defined contribution savings plan for Canadian employees

The company also maintains defined contribution savings plans for its Canadian employees, whereby the company matches employee contributions to a maximum of eight percent of each employee's salary. In 2008, the company contributed \$739,000 (2007 – \$474,000) to this plan, to satisfy, in full, its obligation under this plan.

13. Share Capital, Contributed Surplus And Equity Component

Authorized

The authorized share capital comprises the following:

- Unlimited number of common voting shares
- Unlimited number of first preferred shares
- Unlimited number of second preferred shares

Issued

Only common shares have been issued by the company.

	Number of shares	Amount (\$000)
Balance, Share Capital, December 31, 2006	197,894,015	\$363,082
Issued for cash in public offering (a)	10,450,000	52,250
Issued upon exercise of options (b)	1,518,267	1,466
Shares issued to directors as compensation (c)	108,975	392
Assigned value of options exercised		518
Tax effect of expenditures renounced pursuant to the issuance of flow-through common shares		(9,000)
Share issue costs, net of income taxes		(1,827)
Balance, Share Capital, December 31, 2007	209,971,257	\$406,881
Issued upon exercise of options (b)	1,101,583	893
Shares issued to directors as compensation (c)	108,975	381
Assigned value of options exercised		250
Tax effect of expenditures renounced pursuant to the issuance of flow-through common shares in 2007 (a)		(13,250)
Share issue costs, net of income taxes		(132)
Balance, Share Capital, December 31, 2008	211,181,815	\$395,023
Contributed Surplus:		
Balance, Contributed Surplus, December 31, 2006		\$13,418
Stock – based compensation for share options expensed in 2007 (b)		7,482
Assigned value of options exercised in 2007		(518)
Balance, Contributed Surplus, December 31, 2007		\$20,382
Stock – based compensation for share options expensed in 2008 (b)		5,921
Assigned value of options exercised in 2008		(250)
Balance, Contributed Surplus, December 31, 2008		\$26,053
Equity component of Convertible Debentures, December 31, 2007 and 2008		\$16,823
Total Share Capital, Contributed Surplus and Equity Component:		
December 31, 2007		\$444,086
December 31, 2008		\$437,899

(a) Flow-through share issue – 2007

In November 2007, the company issued from treasury 10,450,000 common shares on a flow-through basis at \$5.00 per share for gross proceeds of \$52.25 million and renounced the related resource expenditures to the flow-through investors effective December 31, 2007. The related tax effect of \$13.25 million was recorded in 2008.

(b) Stock Options

A summary of the company's outstanding stock options, as at December 31, 2008 and 2007 and changes during those years is presented below:

	2008		2007	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Outstanding, beginning of year	17,432,717	\$3.60	16,212,490	\$3.31
Granted	6,226,846	\$2.29	4,311,703	\$3.88
Exercised	(1,101,583)	\$0.81	(1,518,267)	\$0.97
Expired/exchanged	(6,174,876)	\$3.93	(1,573,209)	\$4.00
Outstanding, end of year	16,383,104	\$3.16	17,432,717	\$3.60
Exercisable, end of year	12,423,317	\$3.14	10,204,053	\$3.18

All stock options have been granted for a period of five years. Options granted under the plan are generally fully exercisable after three years

The company offered its employees (excluding directors and officers) the opportunity to exchange significantly “out of the money” options for a reduced number of new options based on the fair value of the options. In the fourth quarter of 2008 Stock-based compensation of \$675,000 was recognized (ie. expensed or capitalized) in relation to the options exchanged.

The table below summarizes unexercised stock options.

Range of Exercise Prices	Number Outstanding	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Number Outstanding	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
At December 31	2008			2007		
\$0.20 – \$0.99	997,034	\$0.77	1.1	1,997,968	\$0.72	1.8
\$1.00 – \$1.99	4,563,623	\$1.34	3.7	1,632,000	\$1.58	2.4
\$2.00 – \$3.99	5,377,938	\$3.31	2.9	6,479,216	\$3.51	3.7
\$4.00 – \$5.99	5,444,509	\$4.98	2.3	7,323,533	\$4.91	3.4
	16,383,104	\$3.16		17,432,717	\$3.60	

In 2008 a compensatory non-cash expense of \$5.9 million (2007 – \$8.3 million) was recorded, reflecting the fair value of stock options amortized over their term. Of this amount, \$4.4 million (2007 – \$5.7 million) was expensed and nil (2007- \$0.4 million) was charged to refining operating costs. A further \$1.5 million (2007 – \$2.2 million) was capitalized to property and equipment.

The fair value of each stock option granted is estimated on the date of grant using the Black-Scholes option-pricing model with weighted average assumptions for grants as follows:

	2008	2007
Risk free interest rate	2.5%	4.1%
Expected option life (years)	3	3
Expected volatility	54%	52%

The weighted average fair value at the date of grant of all options granted in 2008 was \$0.81 per option (2007 – \$1.50).

(c) Share award plan for non-employee directors

Shareholders of the company approved a share award incentive plan for non-employee directors at the company's Annual and Special Meeting of Shareholders on May 10, 2007. Under the plan, a total of 326,925 share units (represented by common shares) were awarded to non-employee directors. In June 2007, 108,975 common shares were issued to directors as compensation under the plan; on January 1, 2008 a further 108,975 share units were vested and the equivalent number of common shares were issued on January 16, 2008; the remaining 108,975 share units vested on January 1, 2009 and were issued on January 5, 2009.

Under the share award plan, share units may be granted to non-employee directors of the company in amounts determined by the Board of Directors on the recommendation of the Governance Committee. Payment under the plan is made by delivering common shares to non-employee directors either through purchases on the TSX or by issuing shares from treasury, subject to certain limitations. The Board of Directors may also elect to pay cash equal to the fair market value of the common shares to be delivered to non-employee directors upon vesting of such share units in lieu of delivering shares.

On March 25, 2008 an additional 283,730 shares were awarded to non-employee directors over a future vesting period. A total of 392,705 share awards were outstanding at December 31, 2008 and have vested or vest on the following dates:

December 31, 2008	5,210
January 1, 2009	108,975
December 31, 2009	5,210
January 1, 2010	136,655
January 1, 2011	136,655
	392,705

In the year ended December 31, 2008, \$125,000 (year ended December 31, 2007 –\$810,000) was charged to expense in respect of awards granted under the share award plan.

14. Related Party Transactions

In 2008 the company paid professional legal fees of \$1.1 million (2007 – \$667,000) to a law firm in which an officer and director of the company were partners. Transactions with the related party occurred within the normal course of business and have been measured at their exchange amount on normal business terms. The exchange amount is the amount of consideration established and agreed to with the related parties.

A portion of the company's conventional crude oil and natural gas exploration and drilling activities, which activities are anticipated to continue in the future, was conducted in an industry-standard joint venture arrangement with a company, an officer of which is also a director of Connacher. Transactions with the joint venture partner occurred within the normal course of business and have been measured at their exchange amount on normal business terms. The exchange amount is the amount of consideration established and agreed to by the company and the joint venture partner.

15. Segmented Information

The company has changed its segmentation in 2008 to better reflect the organization of its business by combining the former Canadian administrative segment with the Canadian oil and gas segment. In Canada, the company is in the business of exploring for and producing crude oil, natural gas and bitumen. In the U.S., the company is in the business of refining and marketing petroleum products. The significant aspects of these operating segments are presented below. Comparative figures have been reclassified.

Year ended December 31	Canada	USA	
(\$000)	Oil and Gas	Refining	Total
2008			
Revenues, net of royalties	\$249,657	\$374,248	\$623,905
Equity interest in Petrolifera earnings	3,085	–	3,085
Dilution gain	7,964	–	7,964
Interest and other income	5,057	377	5,434
Finance charges	34,235	418	34,653
Depletion, depreciation and accretion	48,304	8,144	56,448
Taxes provision (recovery)	1,330	(6,641)	(5,311)
Net earnings (loss)	(11,128)	(15,475)	(26,603)
Property and equipment, net	898,851	86,203	985,054
Goodwill	103,676	–	103,676
Capital expenditures	327,452	24,284	351,736
Total assets	1,287,851	143,824	1,431,675
2007			
Revenues, net of royalties	\$30,722	\$313,050	\$343,772
Equity interest in Petrolifera earnings	6,953	–	6,953
Dilution gain	1,917	–	1,917
Interest and other income	232	516	748
Finance charges	6,858	–	6,858
Depletion, depreciation and accretion	25,887	5,174	31,061
Taxes provision (recovery)	(1,927)	14,932	13,005
Net earnings	12,349	28,612	40,961
Property and equipment, net	617,412	54,010	671,422
Goodwill	103,676	–	103,676
Capital expenditures and acquisitions	307,047	15,915	322,962
Total assets	1,150,655	108,173	1,258,828

16. Supplementary Information

(a) Per share amounts

The following table summarizes the common shares used in per share calculations.

For the years ended December 31 (000)	2008	2007
Weighted average common shares outstanding	210,794	200,092
Dilutive effect of stock options, Convertible Debentures and	3,853	2,674
Weighted average common shares outstanding – diluted	214,647	202,766

(b) Net change in non-cash working capital

For the years ended December 31 (\$000)	2008	2007
Accounts receivable	\$4,274	\$5,872
Inventories	(17,614)	6,058
Due from Petrolifera	(42)	32
Prepaid expenses	299	(995)
Accounts payable and accrued liabilities	45,885	(5,249)
Income taxes payable/recoverable	(9,596)	(7,923)
Total	\$23,206	\$(2,205)

Summary of working capital changes:

(\$000)	2008	2007
Operations	\$(27,583)	\$6,464
Investing	50,789	(8,669)
	\$23,206	\$(2,205)

(c) Supplementary cash flow information

For the years ended December 31 (\$000)	2008	2007
Interest paid	\$78,506	\$24,403
Income taxes paid	1,650	19,001

At December 31, 2007, cash of \$63.2 million was restricted to fund the first year of interest payments on the Second Lien Senior Notes.

17. Commitments, Contingencies And Guarantees

The company's annual commitments under leases for office premises and operating costs, field compression equipment, software license agreements and other equipment are as follows:

2009 – \$3.7 million; 2010 – \$2.7 million; 2011 – \$2.7 million; 2012 – \$2.6 million; 2013 – \$2.6 million; total thereafter \$9.2 million.

Additionally, the company has various guarantees and indemnifications in place in the ordinary course of business, none of which are expected to have a significant impact on the company's financial statements or operations.

18. Subsequent Event

Subsequent to the year end Connacher entered into WTI crude hedges for prices of US \$46.00/bbl and US \$49.50/bbl on a notional volume of 5,000 barrels of oil per day for a significant portion of 2009.

Subsequent to year end Connacher cancelled its Revolving Credit Facilities and put in place a \$20 million demand operating facility for the purpose of issuing letters of credit. The facility is secured by cash and a first lien claim on certain assets of the company.