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IT'S ALL ABOUT THE OILSANDS

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INTERIM REPORT 2007

Connacher's first quarter 2007 was a record first quarter for the company since it was reconstituted with new management and capital in 2001. This applies to conventional production, revenue, cash flow, earnings and capital expenditures, excluding acquisitions. The performance reflects the positive effect of the company's integrated strategy and includes excellent counter-seasonal results, actual and relative to budget, from Montana Refining Company, Inc., our wholly-owned refining company based in Great Falls, Montana, which was acquired effective March 31, 2006.

HIGHLIGHTS

- Conventional production more than doubled, after the sale of approximately 250 boe/d at the end of 2006
- Revenues rose approximately 18 fold to \$65.9 million
- Cash flow from operations, while lower than Q4 2006 due to seasonal factors for refining, rose 537 percent to \$11 million (\$0.06 per share)
- Earnings reached \$5 million (\$0.03 per share), compared to a loss in the first quarter of 2006.
- Capital expenditures exceeded \$100 million
- Progress at our Great Divide SAGD Pod One project was considerable

SUMMARY RESULTS

Three months ended March 31	2007	2006	% Change
FINANCIAL (\$000 except per share amounts)			
Revenues, net of royalties	\$65,923	\$3,635	1,714
Cash flow from operations ⁽¹⁾	10,980	1,725	537
Per share, basic ⁽¹⁾	0.06	0.01	500
Per share, diluted ⁽¹⁾	0.05	0.01	400
Net earnings (loss) for the period	4,984	(666)	848
Per share, basic and diluted	0.03	-	-
Capital expenditures and acquisitions	109,881	300,836	(63)
Cash on hand	66,209	13,073	406
Working capital (deficit)	24,027	(11,061)	317
Long term debt	207,828	-	-
Shareholders' equity	384,593	337,584	14
Total assets	757,205	430,353	76
OPERATING			
Daily production / sales volumes			
Crude oil - bbl/d	905	689	31
Natural gas - mcf/d	9,665	2,600	272
Barrels of oil equivalent - boe/d ⁽²⁾	2,515	1,122	124
Product pricing			
Oil - \$/bbl	49.09	40.93	20
Natural gas - \$/mcf	7.76	6.34	22
Barrels of oil equivalent - \$/boe ⁽²⁾	47.48	39.83	19
Common shares outstanding (000's)			
Weighted average			
Basic	198,119	154,152	29
Diluted	200,008	160,574	25
End of period			
Issued	198,218	191,257	4
Fully diluted	216,606	200,109	8

- (1) Cash flow from operations before working capital changes ("cash flow from operations") 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 from operations includes all cash flow from operating activities and is calculated before changes in non-cash working capital. The most comparable measure calculated in accordance with GAAP would be net earnings. Cash flow from operations is reconciled with net earnings on the Consolidated Statements of Cash Flows and in the accompanying Management's 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 a portion of its future growth expenditures.
- (2) All references to barrels of oil equivalent (boe) are calculated on the basis of 6 mcf:1 bbl. Boes may be misleading, particularly if used in isolation. 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.

LETTER TO SHAREHOLDERS

Connacher reported record financial and operating results during the first quarter of 2007. This reflected healthy energy prices, a solid performance by our Montana refinery, expanded conventional production and was accomplished while we embarked on a substantial capital expenditure program, primarily focused on the development of our first oil sands project at Great Divide, Pod One.

During the reporting period, approximately half of our net operating income was derived from our conventional production and about half from our refinery, underscoring the merits of an integrated approach to the business, even before Great Divide bitumen production comes onstream. Our Montana refining operation performed better than expected during what is traditionally a difficult period for refining and marketing due to winter conditions in our area of operation.

GREAT DIVIDE

Our focus in the reporting period continued to be clearly on the oil sands. During the first quarter we accelerated our development and construction program at Great Divide Pod One, which included residual site preparation, construction of the main processing plant and drilling of horizontal well pairs in preparation for the commencement of operations, targeted for August, 2007. At that time, it is anticipated the plant will be commissioned and we will begin three months of steaming both the injector and producer well bores which comprise the SAGD well pairs. Thereafter, production will commence and should be ramped up towards our objective of 10,000 bbl/d of bitumen production pursuant to our regulatory and governmental licensed approvals. This period is not anticipated to be exceedingly protracted given the quality of reservoir associated with Pod One. Also, as a consequence our anticipated steam/oil ratios ("SORs") are anticipated to be low compared to available analogues known to us at this time. However, it should be understood that actual performance will be the ultimate determinant of SORs and per well productivity.

Our target has always been to complete our plant construction and be ready for startup within 300 days of commencement, following the availability of a suitable plant site on which to construct our facilities, recognizing the plant is anticipated to have a useful life exceeding 25 years or more. As the plant is situated on muskeg, suitable preparation of the site was critical to confidence in having a stable platform on which to build our processing, steam generating and water handling and cleaning facilities. We made every effort to manage costs and mitigate overruns by using a modular approach, taking advantage of the existing proximate infrastructure, including the main paved highway between Edmonton, Alberta, the provincial capital, and Fort McMurray, the capital of the oil sands.

Unfortunately, as evidenced by recent developments as described in a press release issued after the end of the reporting period, our pre-planning and modular approach served to contribute to our cost control, but recent events, inflationary pressures, some scope changes and some overlooked items previously not budgeted, resulted in our estimate to complete the Pod One plant and related developments increasing by about 13 percent to approximately \$290 million, compared to our earlier estimate of \$256 million. Included in both estimates are sunk costs to identify Pod One and secure the acreage, among other costs, of \$24 million. Also, both estimates contain provision for capitalized interest related to servicing the Term Loan B indebtedness, which will be paid prospectively as due and certain operating costs estimates which will be capitalized until production ramps up and commerciality is obtained after steaming and then startup.

Connacher had intended to finance a portion of these additional expenditures through the use of a portion of a bought-deal underwritten financing for approximately \$50 million, comprised of both common equity and flow-through common equity from treasury, to be issued pursuant to a short-form prospectus. Unfortunately, the combination of cost overruns and a minor short-term downturn in the company's conventional production levels, arising from a variety of reasons, caused the transaction to be terminated by mutual agreement among the company and members of the underwriting syndicate. Connacher is now advancing alternative financing arrangements, which will provide the company with continued financial liquidity. Additional permanent capital will eventually be required by the company to maintain its growth profile and achieve its objectives, including timely initiation of and then completion of construction and development of its second Pod at Great Divide.

In this regard, Connacher intends to submit an application to the Alberta Energy and Utilities Board ("AEUB") and other related regulators and government departments, including Alberta Environment ("AE") and Alberta Sustainable Resource Development ("ASRD") for permission to proceed with the development of its Pod Two ("Algar Project"). This project is expected to virtually replicate Pod One in scope and scale at a

target output rate of 10,000 bbl/d of bitumen. It was identified and confirmed by drilling of core holes and by 3D seismic during the past two years or so and is believed to have the requisite characteristics for sustainable commercial development. Assuming the application is submitted in late May as anticipated, it would likely be early 2008 before actual field work could be initiated by Connacher to build related facilities and infrastructure, although as with Pod One considerable engineering and design work could proceed throughout the balance of this year, so the company is fully-prepared to proceed when the regulatory approval process is completed and stakeholder consultation is also accomplished. Costs are anticipated to be higher than Pod One due to inflationary pressures, but attractive economic returns are still anticipated for this scale of SAGD operations.

During the latter part of 2006 and in the first quarter of 2007, Connacher completed its 3D seismic program over the balance of its original lease block and also drilled 81 new core holes, including those in and around Pod Two and Pod Four. Some of the cores taken from our Pod Two drilling are among the best, if not the best, and thickest cores, we have yet seen at Great Divide, including at Pod One where we consider the reservoir to be top decile in its critical characteristics. We have now completed 131 core holes at Great Divide, including 11 in 2004, 19 in 2005, 26 in the first and last quarters of 2006 and 75 thus far in 2007. This density of core holes is still considered relatively modest, as we own or control approximately 2,250 legal subdivisions or LSDs, which are each 40 acres in size. This underscores in part the benefit of coordinating 3D seismic with logging and coring in Connacher's efforts to establish new accumulations or pods.

As a consequence of our new work in 2007, including the considerable progress on our plant at Pod One, which can impact on reserve recognition and reserve values as costs have already been incurred, we intend to have our independent engineering consultant update our reserve report for Great Divide. It is expected this could take up to two months to complete, so results are accordingly expected to be available sometime this summer, most likely in July 2007. It should be noted that previous analysis may have already recognized some of the reserves or resources which might be assigned to Connacher's acreage in earlier reports, although certain resources may be upgraded to reserve status and possible reserves may also be upgraded to proved non-producing status, depending upon the extent and nature of such prior recognition.

Permanent transportation alternatives continue to be evaluated for our dilbit production from Pod One. It is anticipated trucking alternatives for both diluent and dilbit after blending will be utilized, until the correct and economically viable long-term alternative is defined.

CONVENTIONAL PRODUCTION

Connacher's conventional production averaged 2,515 boe/d during the first quarter of 2007, a marked increase of 124 percent from levels achieved last year and occurred despite having sold approximately 250 boe/d in late 2006. This reflects the impact of some new drilling but mostly the acquisition of Luke Energy Ltd. ("Luke") in March 2006. Luke has now been amalgamated into Connacher. While Connacher's total conventional production has declined from peak levels achieved in mid-2006 immediately after the Luke purchase, this reflects the nature of some of these properties as they are only accessible during the winter, generally from January through March and the impact of having sold some minor/non-strategic properties in December 2006. As a result, normal declines were expected to occur until we could activate programs during the first quarter of each year. We had a very successful winter drilling program and added considerable tested deliverability, estimated at approximately 11 mmcf/d based on long-term tests, with sustained initial productivity more likely to be in the 6-7 mmcf/d range. Circumstances and timing precluded us from tying in these new wells. There are also a number of additional offset locations which have been identified. Accordingly, their impact will have to await next winter. Also, certain work over initiatives were completed but are not yet affecting current production, largely due to weather and mechanical and other issues related to third party equipment and services provided in the area. A new discovery at Seal, Alberta, is now onstream at over one mmcf/d (approximately 170 boe/d).

While we have recently experienced production levels below the first quarter average, these are being remedied, corrected or overcome and in any event are of relative limited consequence to the company's overall thrust and financial results. Separately, we would advise that our independent engineers are also expected to complete an update of our conventional reserve estimates, with an effective date of July 1, 2007, on roughly the same timetable as that contemplated for our oil sands reserves and resources.

MONTANA REFINING

Montana Refining Company, Inc. ("MRCI"), our wholly-owned refining subsidiary, turned in an excellent quarter. Its operating statistics and financial performance exceeded our budgetary expectations and overcame historic seasonal influences, which tend to adversely affect refining and marketing during winter months, due to low demand for refined products in general and asphalt in particular. Various factors contributed

to this performance, including higher product prices, better than expected product yields, higher than expected throughput, a lower crude cost and some positive developments in the asphalt market.

To mitigate the seasonal fluctuation in asphalt pricing and to allow the company to operate at a higher utilization rate and profitability than would otherwise be achievable, we successfully constructed a 150,000 barrel asphalt storage tank at our refinery. We are very pleased with our investment in MRCI for its role in providing profitable returns, credit capacity and flexibility and the prospect of an attractive payout while eventually fulfilling its intended objective of providing a hedge against heavy oil price differentials, once bitumen production commences at Great Divide Pod One later this year.

As disclosed in a recent press release, MRCI received notification from the United States Environmental Protection Agency that its National Enforcement Investigations Centre would be conducting a Clean Water Act compliance inspection in respect of the refinery. The purpose of this inspection was to determine compliance with applicable environmental legislation, approvals and permits. MRCI cooperated in connection therewith; the compliance inspection occurred on April 24, 2007, and a report is awaited. No significant issues appear to have arisen during the review.

Other Developments

Readers are referred to our website at www.connacheroil.com for updated pictures of the Pod One plant at Great Divide. Click on Operations/ Great Divide/Photo Gallery to view the progress towards completion.

The results of the company's Annual and Special Meeting of Shareholders, scheduled to be held in Calgary, Alberta on May 10, 2007 at 3:00 PM at the Calgary Petroleum Club, will be reported and included in our next interim report.

Connacher remains optimistic about its future. We will complete Pod One on time and complete current financing initiatives to fund its increased costs. At the same time we will continue to meet our obligations to all our suppliers, creditors and lenders and fulfill our responsibilities to our common shareholders. We retain a significant, valuable and unfettered 26 percent equity investment in Petrolifera Petroleum Limited, which holding has a current market value in excess of \$225 million against our net cash investment of only \$7 million, after a recent exercise of share purchase warrants. This investment remains a financial safety valve for Connacher, provides us with equity earnings and exposes Connacher shareholders to excellent growth potential. We have great growth potential in the oil sands at Great Divide. We have other solid business units that contribute to our overall diversity, strength, resilience and financial performance.

We have generated about \$50 million of cash flow during the past twelve months to supplement the debt and equity capital we have secured. This has enabled Connacher to remain as one of the few, if only, smaller independent companies active in the oil sands. This has been a considerable accomplishment which could only have been achieved with the ongoing support of our shareholders. It is appreciated.

Respectfully submitted on behalf of the Board of Directors,

Richard A. Gusella
President and Chief Executive Officer
May 8, 2007

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is dated as of May 8, 2007 and should be read in conjunction with the unaudited consolidated financial statements of Connacher Oil and Gas Limited ("Connacher" or the "company") for the three months ended March 31, 2007 and 2006 as contained in this interim report and the MD&A and audited financial statements for the years ended December 31, 2006 and 2005 as contained in the company's 2006 annual report. The unaudited consolidated financial statements for the three months ended March 31, 2007 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.

Additional information relating to Connacher, including Connacher's Annual Information Form is on SEDAR at www.sedar.com.

FORWARD-LOOKING INFORMATION

Information in this report contains forward-looking information based on current expectations, estimates and projections of future production, capital expenditures and available sources of financing and estimates of reserves, resources and future net revenues and exploration and development plans. It should be noted forward-looking information involves a number of risks and uncertainties and actual results may vary materially from those anticipated by the company. There can be no assurance that the plans, intentions or expectations upon which these forward-looking statements are based will occur. Forward-looking statements are subject to risks, uncertainties and assumptions, including those discussed in the company's Annual Information Form for the year ended December 31, 2006, which include, without limitation, changes in market conditions, law or governing policy, operating conditions and costs, operating performance, demand for crude oil and natural gas, price and exchange rate fluctuations, commercial negotiations, regulatory processes and approvals and technical and economic factors. Although Connacher believes that the expectations represented in such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement. The forward-looking statements included in this MD&A are made as of the date of the MD&A and Connacher undertakes no obligation to publicly update such forward-looking statements to reflect new information, subsequent events or otherwise unless so required by applicable securities laws. 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.

FINANCIAL AND OPERATING REVIEW

PETROLEUM AND NATURAL GAS PRODUCTION, PRICING AND REVENUE

For the three months ended March 31	2007	2006
Daily production / sales volumes		
Crude oil – bbl/d	905	689
Natural gas – mcf/d	9,665	2,600
Combined – boe/d	2,515	1,122
Product pricing (\$)		
Crude oil – per bbl	49.09	40.93
Natural gas – per mcf	7.76	6.34
Boe – per boe	47.48	39.83
Revenue (\$000)		
Petroleum and natural gas revenue – gross	10,747	4,022
Royalties	(2,540)	(811)
Petroleum and natural gas revenue – net	8,207	3,211

In the first quarter of 2007, net petroleum and natural gas revenues were up 156 percent to \$8.2 million from \$3.2 million in 2006. This was primarily attributable to a 272 percent increase in natural gas production and a 31 percent increase in crude oil sales volumes, primarily resulting from the Luke acquisition in March 2006. Increased conventional product selling prices also contributed to this increase. Although world oil selling prices were down approximately eight percent from the first quarter of 2006, the company's average crude oil selling price increased by 20 percent

to \$49.09 per barrel due to the impact of selling higher quality crude oil and NGLs in the current year. Although North American natural gas prices were down approximately 20 percent from the first quarter of 2006, the company's natural gas sales prices increased 22 percent in 2007 as a result of achieving much better industry market pricing for our larger sales volumes in the current year.

In the first quarter of 2007, the company entered into a "costless collar" contract with a third party to sell approximately one half of its of natural gas production. Mitigating some downside natural gas pricing risk, the company will receive a minimum of US \$7.00 per mmbtu and a maximum of US \$9.50 per mmbtu on a national quantity of 5,000 mmbtu/d of natural gas sold between April 1, 2007 and October 31, 2007. This transaction was not meant 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 reserves-based line of credit, which is considered very important during a period of rapid growth with significant capital expenditures.

ROYALTIES ON PETROLEUM AND NATURAL GAS SALES

For the three months ended March 31

(\$000 except per boe)	2007		2006	
	Total	Per boe	Total	Per boe
Royalties	\$2,540	\$11.22	\$811	\$8.02
As a percentage of petroleum and natural gas revenue		23.6%		20.0%

Royalties represent charges against production or revenue by governments and landowners. Royalties in the first quarter of 2007 were \$2.5 million (\$11.22 per boe, or 23.6 percent of petroleum and natural gas revenue) compared to \$810,000 in 2006 (\$8.02 per boe, or 20 percent of petroleum and natural gas revenue). From year to year, royalties can change based on changes to the weighting in the product mix which is subject to different royalty rates, and rates usually escalate with increased product prices. The increase from 2006 to 2007 reflects market conditions related to increased product prices and production volumes.

PETROLEUM AND NATURAL GAS ("PNG") OPERATING EXPENSES AND NETBACKS

Petroleum and Natural Gas Netbacks ⁽¹⁾

For the three months ended March 31

(\$000 except per boe)	2007		2006		% Change	
	Total	Per boe	Total	Per boe	Total	Per boe
Average daily production (boe/d)		2,515		1,122		
Petroleum and natural gas revenue	\$10,747	\$47.48	\$4,022	\$39.83	173	22
Royalties	(2,540)	(11.22)	(811)	(8.02)	241	52
Net PNG revenue	8,207	36.26	3,211	31.81	155	14
Operating costs	(1,932)	(8.54)	(831)	(8.24)	132	4
PNG netback	\$6,275	\$27.72	\$2,380	\$23.57	164	18

(1) Calculated by dividing related revenue and costs by total boe produced, resulting in an overall combined company netback. 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 that provides management with performance measures and provides shareholders and investors with a measurement of the company's efficiency and its ability to fund future growth through capital expenditures. Operating netbacks are reconciled to net earnings below.

In the first quarter of 2007 operating costs of \$1.9 million were 132 percent higher than in the same prior period, and on a per unit basis, increased by four percent to \$8.54 per boe reflecting the higher cost environment in 2007 and the substantial increases in production volumes during the year. However, higher product prices resulted in higher operating netbacks in 2007.

Reconciliation of PNG Netback to Net Earnings ⁽¹⁾

For the three months ended March 31 (\$000, except per unit amounts)	2007		2006	
	Total	Per boe	Total	Per boe
PNG netback as above	\$6,275	\$27.72	\$2,380	\$23.57
Interest income	120	0.53	424	4.20
Refining margin – net	11,198	49.47	-	-
General and administrative	(3,584)	(15.83)	(956)	(9.47)
Stock-based compensation	(2,946)	(13.02)	(395)	(3.91)
Finance charges	(446)	(1.97)	(84)	(0.83)
Foreign exchange (loss) gain	1,702	7.52	(7)	(0.07)
Depletion, depreciation and amortization	(7,357)	(32.50)	(2,878)	(28.50)
Income taxes	(3,878)	(17.13)	358	3.54
Equity interest in Petrolifera earnings and dilution gain	3,900	17.23	492	4.87
Net earnings (loss)	\$4,984	\$22.02	\$(666)	\$(6.60)

(1) Certain income and expense items included in this reconciliation relate to non-PNG business and, therefore, affect the consolidated net earnings (loss) per boe calculations.

PNG Operating Netbacks by Product

For the period ended March 31

2007 (\$000s, except per unit amounts)	Crude oil		Natural gas	
	Total	Per bbl	Total	Per mcf
Average daily production	905		9,665	
Revenue	\$3,997	\$49.09	\$6,750	\$7.76
Royalties	(939)	(11.53)	(1,601)	(1.84)
Operating costs	(876)	(10.76)	(1,056)	(1.21)
PNG Netback	\$2,182	\$26.80	\$4,093	\$4.71

2006 (\$000s, except per unit amounts)	Crude oil		Natural gas	
	Total	Per bbl	Total	Per mcf
Average daily production	689 bbl/d		2,600 mcf/d	
Revenue	\$2,538	\$40.93	\$1,484	\$6.34
Royalties	(445)	(7.19)	(366)	(1.56)
Operating costs	(529)	(8.53)	(302)	(1.29)
PNG Netback	\$1,564	\$25.21	\$816	\$3.49

Primarily as a result of higher product prices, operating netbacks per boe for the first quarter of 2007 increased 18 percent to \$27.72 per boe compared to \$23.57 in the first quarter of 2006.

REFINING REVENUES AND MARGINS

The quarterly operating results of the Montana refinery since its acquisition on March 31, 2006 are summarized below.

Seasonality of Refining Operations and Sales

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

Refinery throughput - three months ended	June 30, 2006	Sept 30, 2006	Dec 31, 2006	Mar 31, 2007
Crude charged (bbl/d) ⁽¹⁾	6,864	9,613	9,642	9,621
Refinery production (bbl/d) ⁽²⁾	6,932	10,392	10,593	10,634
Sales of produced refined products (bbl/d)	6,266	12,220	9,662	7,777
Sales of refined products (bbl/d) ⁽³⁾	7,384	12,680	10,095	8,254
Refinery utilization (%) ⁽⁴⁾	83%	101%	101%	101%

(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. Note refining capacity has been increased to 9,500 bbl/d in the fourth quarter of 2006.

Feedstocks - three months ended	June 30, 2006	Sept 30, 2006	Dec 31, 2006	Mar 31, 2007
Sour crude oil (%)	98%	92%	92%	92%
Other feedstocks and blends (%)	2%	8%	8%	8%
Total	100%	100%	100%	100%

Revenues and Margins

Refining sales revenue (\$000s)	\$50,967	\$93,752	\$67,155	\$57,596
Refining - crude oil and operating costs (\$000s)	47,104	80,242	55,322	46,398
Refining margin (\$000s)	\$3,863	\$13,510	\$11,833	\$11,198
Refining margin (%)	7.6%	14.4%	17.6%	19.4%

Sales of Produced Refined Products (Volume %)

Gasolines (%)	27%	30%	40%	52%
Diesel fuels (%)	15%	15%	22%	27%
Jet fuels (%)	3%	4%	4%	6%
Asphalt (%)	50%	49%	31%	11%
LPG and other (%)	5%	2%	3%	4%
Total	100%	100%	100%	100%

Averages per Barrel of Refined Product Sold

Refining sales revenue	\$75.85	\$80.37	\$72.52	\$77.53
Less: refining - crude oil purchases and operating costs	70.10	68.78	59.74	62.46
Refining margin	\$5.75	\$11.59	\$12.78	\$15.07

The Montana refinery achieved strong operating performance in the first quarter of 2007 running at 97 percent of capacity with no downtime. Although refining sales revenues of \$57.6 million were down 14 percent from the fourth quarter of 2006, refinery margins increased to 19.4 percent. Sales revenues were down due to seasonally-reduced asphalt sales as normally expected during the winter season.

Current period margins were better than expected due to higher than expected product prices, improved yield of higher value products (gasoline and diesel) achieved by a lighter crude slate and lower than expected crude supply costs.

During the quarter the refinery completed construction of a new 150,000 barrel asphalt storage tank. Work is also progressing well on an improved waste water treatment facility, office expansion, rail loading enhancements and the enhanced sulphur recovery process. The refinery's new NaSH fuel gas scrubbing system operated at 99.8 percent compliance. During the second quarter the company expects to sanction its ultralow sulphur diesel project to allow the company to produce ultraclean fuels by late 2008.

INTEREST AND OTHER INCOME

In the first quarter of 2007, the company earned interest of \$120,000 (March 31, 2006 - \$424,000) on excess funds invested in secure short-term investments.

GENERAL AND ADMINISTRATIVE EXPENSES

In the first quarter of 2007, general and administrative (“G&A”) expenses were \$3.6 million compared to \$956,000 in the first quarter of 2006, an increase of 275 percent, reflecting increased costs associated the company’s growth. On a per unit basis, at \$15.83 per boe sold, this cost is unusually high and is expected to be significantly reduced when bitumen production from Pod One commences. G&A of \$290,000 was capitalized in 2007 (2006 - \$91,000), reflecting additional costs incurred respecting the oil sands development in the pre-production stage.

Non-cash stock-based compensation costs of \$3.5 million were recorded in the first quarter of 2007 (March 31, 2006 -\$604,000). These charges reflect the fair value of all stock options granted and vested in the period. Of this amount, \$2.9 million was expensed (2006 - \$395,000) and \$546,000 was capitalized (2006 - \$209,000).

FINANCE CHARGES AND FOREIGN EXCHANGE

Financing charges were \$446,000 in the first quarter of 2007 compared to \$84,000 reported in the first of quarter of 2006. These charges increased significantly due to the issuance of new debt in 2006. An unrealized foreign exchange gain of \$1.7 million was recorded in the first quarter of 2007 primarily due to the conversion of the US\$180 million oil sands term loan into Canadian dollars for reporting purposes, as the Canadian dollar strengthened in the reporting period.

The company’s main exposure to foreign currency risk relates to the pricing of its crude oil sales, which are denominated in US dollars, and the translation of the US\$180 million oil sands term loan. On an economic basis, the company’s crude oil and bitumen reserves hedge the company’s exposure to foreign currency fluctuations of its US dollar denominated oil sands term loan.

DEPLETION, DEPRECIATION AND ACCRETION (“DD&A”)

Conventional oil and gas depletion expense is calculated using the unit-of-production method based on total estimated proved reserves. Refining properties and other assets are depreciated over their estimated useful lives. DD&A in the first quarter of 2007 was \$7.4 million, a 156 percent increase from last year due to increased production volumes and due to the significant additions made to capital assets in 2006 and 2007. Conventional oil and gas depletion equates to \$25.12 per boe of production compared to \$28.50 per boe last year.

Capital costs of \$239.4 million (March 31, 2006 – \$36.1 million) related to the Great Divide oil sands project, which is in the pre-production stage, and undeveloped land acquisition costs of \$16.3 million (2006 – \$2.5 million) were excluded from the depletion calculation, while future development costs of \$3.2 million (2006 - \$1.8 million) for proved undeveloped reserves were included in the depletion calculation.

Included in DD&A is an accretion charge of \$191,000 (March 31, 2006 - \$47,000) in respect of the company’s estimated asset retirement obligations. These charges will continue to be necessary in the future to accrete the currently booked discounted liability of \$11.6 million to the estimated total undiscounted liability of \$35.8 million over the remaining economic life of the company’s oil and gas properties.

INCOME TAXES

The income tax provision of \$3.9 million in the first three months of 2007 includes a current income tax provision of \$2.7 million, principally related to US refinery operations and a future income tax provision of \$1.2 million reflecting the benefit of increased tax pools during the period.

At March 31, 2007 the company had approximately \$33 million of non-capital losses which do not expire before 2009, \$312 million of deductible resource pools and \$19 million of deductible financing costs.

EQUITY INTEREST IN PETROLIFERA PETROLEUM LIMITED (“PETROLIFERA”)

Connacher accounts for its 26 percent equity investment in Petrolifera on the equity method basis of accounting. Connacher’s equity interest share of Petrolifera’s earnings in the first three months of 2007 was \$3.9 million (March 31, 2006 - \$389,000).

NET EARNINGS

In the first three months of 2007 the company reported earnings of \$5.0 million (\$0.03 per basic and diluted share outstanding) compared to a loss of \$666,000 or \$nil per basic and diluted share for the first three months of 2006. Earnings per boe produced were \$22.02 compared to a loss of \$6.60 per boe in the first three months of 2006. In 2007, the refinery contributed significantly to these results.

SHARES OUTSTANDING

For the first three months of 2007, the weighted average number of common shares outstanding was 198,119,130 (2006 – 154,151,848) and the weighted average number of diluted shares outstanding, as calculated by the treasury stock method, was 200,007,743 (2006 – 160,573,785). The substantial increase in shares outstanding year over year reflects the issuance from treasury of 58 million common shares issued in 2006 for cash proceeds of \$130 million and in connection with the acquisitions of Luke and the Montana refinery assets.

As at May 7, 2007, the company had the following securities issued and outstanding:

- 198,238,448 common shares; and
- 18,270,890 share purchase options.

Details of the exercise provisions and terms of the outstanding options are noted in the consolidated financial statements, included in this interim report.

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2007, the company had working capital of \$24 million, including \$66.2 million of cash dedicated to funding the remaining costs of completing the Pod One oil sands project.

Cash flow from operations before working capital changes (“cash flow”), cash flow per share and cash flow per boe 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. 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 below.

Cash flow per share is calculated by dividing cash flow by the weighted average shares outstanding; cash flow per boe is calculated by dividing cash flow by the quantum of crude oil and natural gas (expressed in boe) sold in the period. 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 a portion of its future growth expenditures.

In addition to available cash, unused debt facilities and cash flow, additional sources of funding in the form of additional equity issuances or additional debt financing may be utilized to provide sufficient funding for working capital purposes and for the company’s 2007 capital program.

The company’s only financial instruments are cash, accounts receivable and payable, bank debt, the interest rate swap and the natural gas costless collar. The company maintains no off-balance sheet financial instruments.

As the company’s long term bank debt is denominated in US dollars, there is a foreign exchange risk associated with its repayment using Canadian currency. As noted above, the company’s crude oil selling prices are established in relation to US dollar denominated markets and, therefore, provide a partial hedge to this exposure.

The interest rate swap was entered into to mitigate some of the interest rate volatility associated with the variable interest rate inherent in all of the company’s debt facilities.

The natural gas costless collar is intended to mitigate some downside natural gas pricing risk and, therefore, protect the risk of reduced cash flow from operations and the risk of reductions to the lending value of its conventional banking facilities, which is considered particularly important in a time of rapid growth with significant capital expenditure.

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

Three months ended March 31

(\$000s)	2007	2006
Net earnings (loss)	\$4,984	\$(666)
Items not involving cash:		
Depletion, depreciation and accretion	7,357	2,878
Stock-based compensation	2,946	395
Financing charges	-	6
Future employee benefits	130	-
Future income tax provision (recovery)	1,165	(388)
Foreign exchange (gain) loss	(1,702)	7
Lease inducement amortization	-	(15)
Dilution gain	-	(103)
Equity interest in Petrolifera earnings	(3,900)	(389)
Cash flow from operations before working capital changes	\$10,980	\$1,725

In the first quarter of 2007, cash flow was \$11 million (\$0.06 per basic and \$0.05 per diluted share), 537 percent higher than the \$1.7 million reported (\$0.01 per basic and diluted share) for the first three months of 2006. A significant portion of this was contributed by the refinery.

CAPITAL EXPENDITURES AND FINANCING ACTIVITIES

Capital expenditures totaled \$110 million in the first quarter of 2007 (first quarter 2006 - \$300.8 million). A breakdown of these expenditures follows:

(\$000)	Three months ended March 31	
	2007	2006
Acquisition of Luke	\$-	\$204,000
Acquisition of refinery assets	-	67,000
Oil sands expenditures	86,512	25,236
Conventional oil and gas expenditures	20,252	4,600
Refinery expenditures	3,117	-
	\$109,881	\$300,836

Oil sands expenditures include exploratory core hole drilling, seismic, lease acquisition on Pods One through Six and costs incurred for the development of Pod One. In the first three months of 2007, 81 exploratory core holes were drilled. In the first quarter of 2006, 20 exploratory core holes were drilled.

Conventional oil and gas expenditures include costs of drilling, completing, equipping and working over conventional oil and gas wells as well as undeveloped land acquisition and seismic expenditures. In 2007, 19 (18 net) conventional oil and gas wells were drilled, resulting in eight cased gas wells; one suspended gas well and two suspended oil wells being evaluated; and eight (seven net) abandoned wells.

A significant part of the company's capital program is discretionary and may be expanded or curtailed based on drilling results and the availability of capital. This is reinforced by the fact that Connacher operates most of its wells and holds an average of over 90 percent working interest in its PNG properties, providing the company with operational and timing controls.

Great Divide Oil Sands Project, Northern Alberta

The company holds a 100 percent working interest in approximately 90,000 acres of oil sands leases in northern Alberta. To date, the focus has been on an approximate 1,586 acre tract ("Pod One") on which approximately \$190 million (\$19 million of these costs are included in accounts payable at March 31, 2007) has been incurred to March 31, 2007 to acquire the oil sands leases, to delineate the oil bearing reservoir, and for facilities related to the development of a 10,000 bbl/d SAGD project. Capital development costs for Pod One are expected to approximate \$290 million, prior to the commencement of bitumen production in the latter part of 2007. The remaining costs will be funded with dedicated cash balances of \$66.2 million, available lines of credit and new financing sources anticipated to be available to the company.

Acquisition of Luke Energy Ltd. ("Luke")

In March 2006 the company closed the purchase of Luke for cash consideration of \$92.7 million and the issuance of 29.7 million Connacher common shares from treasury.

Luke produced natural gas, largely at Marten Creek in northern Alberta and operated most of its high working interest properties. This production was considered strategic to Connacher, as, in Connacher's view, it would provide a physical hedge to its initial requirements for natural gas to create steam for the company's SAGD oil sands project (Pod One) at Great Divide. Based on purchased production volumes and anticipated development programs, the Luke purchase is anticipated, over time, to provide surplus natural gas volumes for sale in the marketplace over and above Connacher requirements at Great Divide. Such volumes may not be physically consumed at Great Divide, but sold to offset purchases from more proximate supply points. Luke was amalgamated with Connacher on January 1, 2007.

Acquisition of Refining Assets in Montana

In March 2006, the company acquired an 8,300 bbl/d refinery located in Great Falls, Montana, USA, for cash of \$61 million and one million Connacher common shares issued from treasury.

This acquisition was considered strategic to provide Connacher with protection against wider and more volatile type of heavy crude oil price differential swings. These have become increasingly frequent in the current higher oil price environment for the type of heavy oil which would be produced at Great Divide. Since its acquisition, the refinery has been a profitable and strong business unit contributing to the company's cash flow.

Connacher completed the purchase of the refining assets and related inventory through a new wholly-owned subsidiary, Montana Refining Company, Inc. ("MRCI"). Its continued profitability will depend largely on the spread between market prices for refined petroleum products and the cost of crude oil.

MRCI's principal source of revenue is from the sale of high value light end products such as gasoline, diesel and jet fuel in markets in the western United States. Additionally, MRCI sells a high grade asphalt into the local market. MRCI's principal expenses relate to crude oil purchases and operating expenses.

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. 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 policies is not meant to be exhaustive.

Oil and Gas Reserves

Under Canadian Securities Regulators' "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 are also 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 under the heading "Full Cost Accounting for Oil and Gas Activities".

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.

NEW SIGNIFICANT ACCOUNTING POLICIES

The company has assessed new and revised accounting pronouncements that have been issued.

In 2007 the company has adopted, as necessary, the Canadian Institute of Chartered Accountants ("CICA") Sections 1530, 3251, 3855 and 3865 on "Comprehensive Income", "Equity", "Financial Instruments – Recognition and Measurement", and "Hedges" respectively, all of which were issued in January 2005. Under the new standards additional financial statement disclosure, namely Consolidated Statement of Other Comprehensive Income, has been introduced that will identify certain gains and losses, including the foreign currency translation adjustments and other amounts arising from changes in fair value, to be temporarily recorded outside the income statement. In addition, all financial instruments, including derivatives, are to be included in the company's Consolidated Balance Sheet and measured, in most cases, at fair values.

BUSINESS RISKS

Connacher is exposed to certain risks and uncertainties inherent in the oil and gas and refining businesses. Furthermore, being a smaller independent company, it is exposed to financing and other risks which may impair its ability to realize on its assets or to capitalize on opportunities which might become available to it. Additionally, through the company's investment in Petrolifera which operates in foreign jurisdictions, it has become exposed to other risks including currency fluctuations, political risk, price controls and varying forms of fiscal regimes or changes thereto which may impair Petrolifera's ability to conduct profitable operations.

The risks arising in the oil and gas industry include price fluctuations for both crude oil and natural gas over which the company has limited control; risks arising from exploration and development activities; production risks associated with the depletion of reservoirs and the ability to market production. Additional risks include environmental and safety concerns.

For the Montana Refinery, certain strategies could be used to reduce some commodity prices and operational risks. No attempt will be made to eliminate all market risk exposures when it is believed the exposure relating to such risk would not be significant to future earnings, financial position, capital resources or liquidity or that the cost of eliminating the exposure would outweigh the benefit. MRCL's profitability will depend largely on the spread between market prices for refined products sold and market prices for crude oil purchased. A substantial or prolonged reduction in this spread could have a significant negative effect on earnings, financial condition and cash flows.

Petroleum commodity futures contracts could be utilized to reduce exposure to price fluctuations associated with crude oil and refined products. Such contracts could be used principally to help manage the price risk inherent in purchasing crude oil in advance of the delivery date and as a hedge for fixed-price sales contracts of refined products. Commodity price swaps and collar options could also be utilized to help manage the exposure to price volatility relating to forecasted purchases of natural gas. Contracts could also be utilized to provide for the purchase of crude oil and other feedstocks and for the sales of refined products. Certain of these contracts may meet the definition of a hedge and may be subject to hedge accounting.

The supply and use of heavy crude oil from the company's Great Divide Oil Sands Project, as a feedstock for the refinery, would provide a physical hedge to this exposure, as planned.

MRCI's operations are subject to normal hazards of operations, including fire, explosion and weather-related perils. Various insurance coverages, including business interruption insurance, are maintained in accordance with industry practices. However, MRCI is not fully insured against certain risks because such risks are not fully insurable, coverage is unavailable, or, in management's judgment, premium costs are prohibitive in relation to the perceived risks.

Additionally, Connacher has issued parental guarantees and indemnifications on behalf of MRCI. This is considered to be in the normal course of business.

The company will require a significant amount of natural gas in order to generate steam for the SAGD process used at Great Divide. The company is exposed to the risk of changes in the price of natural gas, which could increase operating costs of the Great Divide project. This risk is mitigated to a certain extent by the production and sale of natural gas from the company's gas properties at Marten Creek acquired with the purchase of Luke.

Additionally, the company is exposed to exchange rate fluctuations since oil prices and its long term debt are denominated in US dollars, while the majority of its operating and capital costs are denominated in Canadian dollars. On an economic basis, the company's crude oil and bitumen reserves hedge the company's exposure to foreign currency fluctuations of its US dollar denominated term debt.

Bitumen is generally less marketable than light or medium crude oil, and prices received for bitumen are generally lower than those for crude oil. The company is therefore exposed to the price differential between crude oil and bitumen; fluctuations in this differential could have a material impact on the company's profitability. The purchase of the Montana refinery was meant to help mitigate this risk exposure.

The company relies on access to capital markets for new equity to supplement internally generated cash flow and bank borrowings to finance its growth plans. Periodically, these markets may not be receptive to offerings of new equity from treasury, whether by way of private placement or public offerings. This may be further complicated by the limited market liquidity for shares of smaller companies, restricting access to some institutional investors. An increased emphasis on flow-through share financings may accelerate the pace at which junior oil and gas companies become cash-taxable, which could reduce cash flow available for capital expenditures on growth projects. Periodic fluctuations in energy prices may also affect lending policies of the company's banker, whether for existing loans or new borrowings. This in turn could limit growth prospects over the short run or may even require the company to dedicate cash flow, dispose of properties or raise new equity to reduce bank borrowings under circumstances of declining energy prices or disappointing drilling results.

The success of the company's capital programs as embodied in its productivity and reserve base could also impact its prospective liquidity and pace of future activities. Control of finding, development, operating and overhead costs per boe is an important criterion in determining company growth, success and access to new capital sources.

The company attempts to mitigate its business and operational risk exposures by maintaining comprehensive insurance coverage on its assets and operations, by employing or contracting competent technicians and professionals, by instituting and maintaining operational health, safety and environmental standards and procedures and by maintaining a prudent approach to exploration and development activities. The company also addresses and regularly reports on the impact of risks to its shareholders, writing down the carrying values of assets that may not be recoverable.

Furthermore, the company generally relies on equity financing and a bias towards conservative financing of its operations under normal industry conditions to offset the inherent risks of oil and gas exploration, development and production activities. Occasionally the company

utilizes forward sale, fixed price contracts to mitigate reduced product price risk and foreign exchange risk during periods of price improvement, primarily with a view to assuring the availability of funds for capital programs and to enhance the creditworthiness of its assets with its lenders. While hedging activities may have opportunity costs when realized prices exceed hedged pricing, such transactions are not meant to be speculative and are considered within the broader framework of financial stability and flexibility. Management regularly reviews the need to utilize such financing techniques.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the company is accumulated, recorded, processed, summarized and reported to the company's management as appropriate to allow timely decisions regarding required disclosure. The company's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by this MD&A, that the company's disclosure controls and procedures as of the end of such period are effective to provide reasonable assurance that material information related to the company, including its consolidated subsidiaries, is communicated to them as appropriate to allow timely decisions regarding required disclosure.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of the company is responsible for designing adequate internal controls over the company's financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. There have been no changes in the company's systems of internal control over financial reporting that would materially affect, or is reasonably likely to materially affect, the company's internal controls over financial reporting.

It should be noted that while the company's Chief Executive Officer and Chief Financial Officer believe that the company's disclosure controls and procedures provide a reasonable level of assurance that they are effective and that the internal controls over financial reporting are adequately designed, they do not expect that the financial disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. 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.

OUTLOOK

The company's business plan anticipates substantial growth. Emphasis will continue to be on delineating and developing the Great Divide oil sands project in Alberta while continuing to develop the company's recently-expanded conventional production base and profitably operating the Montana refinery. Additional financing may be required for the Great Divide oil sands project, the company's conventional petroleum and natural gas assets and for the Montana refinery.

QUARTERLY RESULTS

Fluctuations in results over the previous eight quarters are due principally to variations in oil and gas prices and the acquisitions of Luke Energy and the Montana refinery in 2006, both of which increased revenues substantially. Additionally, operating and general and administrative costs increased due to higher staff levels necessitated by the company's growth. Depletion, depreciation and amortization increased as a result of higher production volumes and additions to capital assets.

Three Months Ended	2005			2006			2007	
	Jun 30	Sept 30 ⁽³⁾	Dec 31	Mar 31	Jun 30	Sept 30	Dec 31	Mar 31
Financial Highlights (\$000 except per share amounts) – Unaudited								
Revenue net of royalties	2,107	3,222	2,978	3,635	61,239	103,110	76,700	65,923
Cash flow from operations before working capital changes ⁽¹⁾	877	1,978	1,238	1,725	9,499	14,957	14,015	10,980
Basic, per share ⁽¹⁾	0.01	0.02	0.01	0.01	0.05	0.08	0.08	0.06
Diluted, per share ⁽¹⁾	0.01	0.02	0.01	0.01	0.05	0.08	0.07	0.05
Net earnings (loss)	(230)	(1,034)	582	(666)	(2,419)	6,771	3,267	4,984
Basic and diluted per share	-	(0.01)	-	-	(0.01)	0.03	0.02	0.03
Capital expenditures	5,649	2,870	2,241	300,836	34,280	41,449	74,960	109,881
Proceeds on disposal of PNG properties	-	-	-	-	-	-	10,000	-
Cash on hand	2,629	67,708	75,511	-	7,505	14,450	142,391	66,209
Working capital surplus (deficiency)	854	67,440	75,427	(11,061)	(42,483)	(39,942)	118,626	24,027
Long term debt	-	-	-	-	-	-	209,754	207,828
Shareholders' equity	41,090	113,081	129,108	337,584	340,639	378,730	385,398	384,593
Operating Highlights								
Daily production / sales volumes								
Natural gas - mcf/d	1,416	497	86	2,600	15,172	12,711	11,291	9,665
Crude oil - bbl/d	702	808	775	689	1,026	1,059	1,139	905
Equivalent - boe/d ⁽²⁾	938	891	789	1,122	3,554	3,177	3,021	2,515
Product pricing								
Crude oil - \$/bbl	41.23	53.40	41.54	40.93	61.45	62.53	46.65	49.09
Natural gas - \$/mcf	0.99	1.88	7.55	6.34	5.66	5.33	6.57	7.76
Selected Highlights - \$/boe ⁽²⁾								
Weighted average sales price	32.35	49.48	41.61	39.83	41.88	42.16	42.15	47.48
Royalties	8.06	11.73	7.76	8.02	10.43	10.72	9.00	11.22
Operating costs	7.42	7.69	8.90	8.24	7.63	7.99	9.27	8.54
PNG netback ⁽⁴⁾	16.87	30.06	24.95	23.57	23.82	23.45	23.88	27.72
Common Share Information								
Shares outstanding at end of period (000)	93,013	134,236	139,940	191,257	191,924	197,878	197,894	198,218
Weighted average shares outstanding for the period								
Basic (000)	92,875	103,851	136,071	154,152	191,672	193,587	193,884	198,119
Diluted (000)	95,555	106,397	142,507	160,574	198,931	200,572	204,028	200,008
Volume traded during quarter (000)	16,821	180,848	100,246	148,184	80,347	48,849	46,444	55,292
Common share price (\$)								
High	1.05	2.69	4.20	6.07	5.05	4.55	4.43	4.13
Low	0.68	0.76	1.09	3.47	3.10	3.09	3.17	3.07
Close (end of period)	0.82	2.54	3.84	4.95	4.30	3.60	3.49	3.86

(1) Cash flow from operations before working capital changes 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 from operations before working capital changes includes all cash flow from operating activities and is calculated before changes in non-cash working capital. The most comparable measure calculated in accordance with GAAP would be net earnings. Cash flow from operations before working capital changes 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 a portion of its future growth expenditures.

(2) All references to barrels of oil equivalent (boe) are calculated on the basis of 6 mcf : 1 bbl. Boes may be misleading, particularly if used in isolation. 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.

(3) In the third quarter of 2005, the company discontinued consolidating the financial and operational results of Petrolifera Petroleum Limited. Comparative figures have not been restated.

(4) PNG 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. Netbacks by product type are disclosed in the accompanying MD&A.

CONSOLIDATED BALANCE SHEETS

Connacher Oil and Gas Limited
(Unaudited)

(\$000)	March 31, 2007	December 31, 2006
ASSETS		
CURRENT		
Cash and cash equivalents	\$-	\$19,603
Restricted cash (Note 9 (c))	66,209	122,788
Accounts receivable	31,138	30,956
Refinery inventories (Note 4)	38,995	24,437
Prepaid expenses	1,159	1,525
Due from Petrolifera	-	32
	137,501	199,341
Property and equipment	487,021	384,311
Goodwill	103,676	103,676
Deferred costs	3,510	4,005
Investment in Petrolifera	25,497	21,597
	\$757,205	\$712,930
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	\$72,160	\$57,571
Income taxes payable	3,137	3,644
Current portion of bank debt	38,100	19,500
Due to Petrolifera	77	-
	113,474	80,715
Asset retirement obligations (Note 5)	11,556	7,322
Employee future benefits (Note 9 (d))	513	388
Long term bank debt	207,828	209,754
Future income taxes	39,241	29,353
	372,612	327,532
SHAREHOLDERS' EQUITY		
Share capital and contributed surplus (Note 6)	371,272	376,500
Accumulated other comprehensive loss (Note 3)	(691)	(130)
Retained earnings	14,012	9,028
	384,593	385,398
	\$757,205	\$712,930

CONSOLIDATED STATEMENTS OF OPERATIONS AND RETAINED EARNINGS

Connacher Oil and Gas Limited

Three Months Ended March 31 (Unaudited)

(\$000, except per share amounts)	2007	2006
REVENUE		
Petroleum and natural gas revenue, net of royalties	\$8,207	\$3,211
Refining and marketing sales	57,596	-
Interest and other income	120	424
	65,923	3,635
EXPENSES		
Petroleum and natural gas operating costs	1,932	831
Refining – crude oil purchases and operating costs	46,398	-
General and administrative	3,584	956
Stock-based compensation (Note 6)	2,946	395
Finance charges	446	84
Foreign exchange loss (gain)	(1,702)	7
Depletion, depreciation and accretion	7,357	2,878
	60,961	5,151
Earnings (loss) before income taxes and other items	4,962	(1,516)
Current income tax provision	2,713	30
Future income tax provision (recovery)	1,165	(388)
	3,878	(358)
Earnings (loss) before other items	1,084	(1,158)
Equity interest in Petrolifera earnings	3,900	389
Dilution gain	-	103
NET EARNINGS (LOSS)	4,984	(666)
RETAINED EARNINGS, BEGINNING OF PERIOD	9,028	2,075
RETAINED EARNINGS, END OF PERIOD	\$14,012	\$1,409
EARNINGS PER SHARE (Note 9 (a))		
Basic	\$0.03	-
Diluted	\$0.03	-

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

Connacher Oil and Gas Limited

Three Months Ended March 31 (Unaudited)

(\$000)	2007
Net earnings	\$4,984
Foreign currency translation adjustment, net of income taxes of \$241	(561)
Comprehensive income	\$4,423

CONSOLIDATED STATEMENT OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Connacher Oil and Gas Limited

Three Months Ended March 31 (Unaudited)

(\$000)	2007
Balance, beginning of period	\$(130)
Foreign currency translation adjustment	(561)
Balance, end of period	\$(691)

CONSOLIDATED STATEMENTS OF CASH FLOW

Connacher Oil and Gas Limited
Three Months Ended March 31 (Unaudited)

(\$000)	2007	2006
Cash provided by (used in) the following activities:		
OPERATING		
Net earnings (loss)	\$4,984	\$(666)
Items not involving cash:		
Depletion, depreciation and accretion	7,357	2,878
Stock-based compensation	2,946	395
Financing charges	-	6
Employee future benefits	130	-
Future income tax provision (recovery)	1,165	(388)
Foreign exchange loss (gain)	(1,702)	7
Dilution gain	-	(103)
Lease inducement amortization	-	(15)
Equity interest in Petrolifera earnings	(3,900)	(389)
Cash flow from operations before working capital changes	10,980	1,725
Changes in non-cash working capital (Note 9 (b))	6,922	4,243
	17,902	5,968
FINANCING		
Issue of common shares, net of share issue costs	280	94,922
Increase in bank debt	27,600	17,600
Repayment of bank debt	(9,000)	-
Deferred financing costs	-	(1,947)
	18,880	110,575
INVESTING		
Acquisition and development of oil and gas properties	(105,294)	(29,556)
Decrease in restricted cash	56,579	-
Acquisition of Luke Energy Ltd.	-	(92,227)
Acquisition of refining assets	-	(62,041)
Change in non-cash working capital (Note 9 (b))	(7,105)	4,844
	(55,820)	(178,980)
NET DECREASE IN CASH AND CASH EQUIVALENTS	(19,038)	(62,437)
Impact of foreign exchange on foreign currency denominated cash balances	(565)	-
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	19,603	75,511
CASH AND CASH EQUIVALENTS, END OF PERIOD	\$-	\$13,074

Supplementary information – Note 9

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Connacher Oil and Gas Limited

Period ended March 31, 2007 (Unaudited)

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. Operating in Canada, and in the U.S. through its subsidiary Montana Refining Company, Inc. (“MRCI”), the company is in the business of exploring, developing, producing, refining and marketing conventional petroleum and natural gas and has recently commenced exploration and development of bitumen in the oil sands of northern Alberta.

2. SIGNIFICANT ACCOUNTING POLICIES

The interim Consolidated Financial Statements have been prepared following the same accounting policies and methods of computation as indicated in the annual audited Consolidated Financial Statements for the year ended December 31, 2006, except as described in Note 3. The disclosures provided below do not conform in all respects to those included with the annual audited Consolidated Financial Statements. The interim consolidated Financial Statements should be read in conjunction with the annual audited Consolidated Financial Statements and the notes thereto for the year ended December 31, 2006.

3. NEW ACCOUNTING STANDARDS

Effective January 1, 2007 the company adopted CICA Handbook sections 1530, 3251, 3855 and 3865 relating to Comprehensive Income, Equity, Financial Instruments – Recognition and Measurement, and Hedges, respectively. Under the new standards, additional financial statement disclosure, namely the Consolidated Statement of Comprehensive Income, has been introduced. This statement identifies certain gains and losses, which in the company’s case include only foreign currency translation adjustments arising from translation of the company’s U.S. refining subsidiary which is considered to be self-sustaining, that are recorded outside the income statement. Additionally, a separate component of equity, Accumulated Other Comprehensive Income (“AOCI”), has been introduced in the consolidated balance sheet to record the continuity of other comprehensive income balances on a cumulative basis.

The adoption of comprehensive income has been made in accordance with the applicable transitional provisions. Accordingly, the December 31, 2006 period end accumulated foreign currency translation adjustment balance of \$130,000 has been reclassified to AOCI. In addition, the change in the accumulated foreign currency translation adjustment balance for the three months ended March 31, 2007 of \$561,000 is now included in the Statement of Comprehensive Income (three months ended March 31, 2006 – nil) . Finally, all financial instruments, including derivatives, are recorded in the company’s consolidated balance sheet and measured at their fair values.

Under section 3855, the company is required to classify its financial instruments into one of five categories. The company has classified all of its financial instruments, with the exception of the oil sands term loan, as Held for Trading, which requires measurement on the balance sheet at fair value with any changes in fair value recorded in income. This classification has been chosen due to the nature of the company’s financial instruments, which, except for the oil sands term loan, are of a short-term nature such that there are no material differences between the carrying values and the fair values of these financial statement components. Transaction costs related to financial instruments classified as Held for Trading are recorded in income in accordance with the new standards.

The US \$180 million oil sands term loan has been classified as other liabilities and is accounted for on the amortized cost basis.

The adoption of section 3865, “Hedges”, has had no effect on the company’s consolidated financial statements as the company does not account for its derivative financial instruments as hedges.

(\$000)	Increase/(Decrease)
Other comprehensive income	(561)
Accumulated other comprehensive income	(561)

Effective January 1, 2007, the company adopted the revised recommendations of CICA Handbook section 1506, Accounting Changes.

The new recommendations permit voluntary changes in accounting policy only if they result in financial statements which provide more relevant and reliable financial information. Accounting policy changes must be applied retrospectively unless it is impractical to determine the period or cumulative impact of the change in policy. Additionally, when an entity has not applied a new primary source of GAAP that has been issued but is not yet effective, the entity must disclose that fact along with information relevant to assessing the possible impact that application of the new primary source of GAAP will have on the entity's financial statements in the period of initial application.

As of January 1, 2008, the company will be required to adopt two new CICA Handbook requirements, section 3862, "Financial Instruments - Disclosures" and section 3863, "Financial Instruments - Presentation" which will replace current 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. The new presentation standard essentially carries forward the current presentation requirements. The company is assessing the impact of these new standards on its consolidated financial statements and anticipates that the main impact will be in terms of the additional disclosures required.

As of January 1, 2008, the company will be required to adopt 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. The company is assessing the impact of this new standard on its consolidated financial statements and anticipates that the main impact will be in terms of the additional disclosures required.

4. REFINERY INVENTORIES

Inventories consist of the following:

(\$000)	March 31, 2007	December 31, 2006
Crude oil	\$2,777	\$3,520
Other raw materials and unfinished products (1)	1,389	1,292
Refined products (2)	31,716	17,440
Process chemicals (3)	1,745	909
Repairs and maintenance supplies and other	1,368	1,276
	\$38,995	\$24,437

- (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.

5. 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 petroleum and natural gas properties and facilities.

(\$000)	Three months ended March 31, 2007	Year ended December 31, 2006
Asset retirement obligations, beginning of period	\$7,322	\$3,108
Liabilities incurred	4,043	2,384
Liabilities acquired	-	2,109
Liabilities disposed	-	(864)
Change in estimated future cash flows	-	237
Accretion expense	191	348
Asset retirement obligations, end of period	\$11,556	\$7,322

Liabilities incurred in 2007 have been estimated using a discount rate of eight percent to more accurately reflect the company's credit-adjusted risk free interest rate given its current capital structure. 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.

6. SHARE CAPITAL AND CONTRIBUTED SURPLUS

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)
Share Capital:		
Balance, December 31, 2006	197,894,015	\$363,082
Issued upon exercise of options (a)	324,433	289
Tax effect of expenditures renounced pursuant to the issuance of flow-through common shares (b)		(9,000)
Assigned value of options exercised	-	105
Share issue costs		(9)
Balance, Share Capital, March 31, 2007	198,218,448	\$354,467
Contributed Surplus:		
Balance, December 31, 2006		\$13,418
Fair value of share options granted		3,492
Assigned value of options exercised		(105)
Balance, Contributed Surplus, March 31, 2007		\$16,805
Total Share Capital and Contributed Surplus:		
December 31, 2006		\$376,500
March 31, 2007		\$371,272

(a) Stock Options

A summary of the company's outstanding stock options, as at March 31, 2007 and 2006 and changes during those periods is presented below:

	2007		2006	
	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price
Outstanding, beginning of period	16,212,490	\$3.31	8,592,600	\$1.49
Granted	2,744,833	3.88	335,000	4.80
Exercised	(324,433)	0.89	(436,366)	(0.73)
Expired	(213,000)	3.75	-	-
Outstanding, end of period	18,419,890	\$3.44	8,491,234	\$1.66
Exercisable, end of period	9,617,198	\$3.02	3,192,997	\$0.96

All stock options have been granted for a period of five years. Options granted under the plan are generally fully exercisable after two or three years and expire five years after the date granted. The table below summarizes unexercised stock options.

Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life at March 31, 2007
\$0.20 - \$0.99	2,941,802	2.4
\$1.00 - \$1.99	1,871,000	3.2
\$2.00 - \$3.99	6,206,833	4.4
\$4.00 - \$5.56	7,400,255	4.0
	18,419,890	

In 2007 a compensatory non-cash expense of \$3.5 million (2006 - \$604,420) was recorded, reflecting the amortization of the fair value of stock options over the vesting period. Of this amount, \$2.9 million (2006 - \$394,180) was expensed and \$546,000 (2006 - \$210,000) 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:

	2007	2006
Risk free interest rate	4.5%	4.1%
Expected option life (years)	3	3
Expected volatility	68%	48%

The weighted average fair value at the date of grant of all options granted in the first quarter of 2007 was \$1.86 per option (2006 - \$1.83).

(b) Flow through shares

Effective December 31, 2006, the company renounced \$30 million of resource expenditures to flow-through investors. The related tax effect of \$9 million of these expenditures was recorded in 2007. The company incurred all of the required expenditures related to these flow-through shares in 2006 and 2007.

7. COMMODITY PRICE RISK MANAGEMENT

During the first quarter of 2007 the company entered into a costless collar arrangement whereby the sales price for five million cubic feet per day of the company's natural gas production was fixed within a range of US\$7.00 per mmbtu – US\$9.50 per mmbtu. The effective date of the arrangement commences April 1, 2007 and continues until October 31, 2007. At March 31, 2007 the fair value of this collar was a liability of \$57,000.

8. SEGMENTED INFORMATION

In Canada, the company is in the business of exploring and producing conventional petroleum and natural gas and is engaged in the exploration and development of bitumen in the oil sands of northern Alberta. 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. Included in Canadian administrative assets is the company's carrying value of its investment in Petrolifera.

Three months ended March 31 (\$000)	Canada Oil and Gas	Canada Administrative	USA Refining	Argentina Oil and Gas	Total
2007					
Revenues, net of royalties	\$8,207	\$-	\$57,596	\$-	\$65,803
Equity interest in Petrolifera earnings	-	3,900	-	-	3,900
Interest and other income	13	-	107	-	120
Crude oil purchase and operating costs	1,932	-	46,398	-	48,330
General and administrative	3,584	-	-	-	3,584
Stock-based compensation	-	2,946	-	-	2,946
Finance charges	371	-	75	-	446
Foreign exchange gain	(1,702)	-	-	-	(1,702)
Depletion, depreciation and accretion	6,100	-	1,257	-	7,357
Taxes provision	224	-	3,654	-	3,878
Net earnings (loss)	2,512	(2,855)	5,327	-	4,984
Property and equipment, net	433,394	2,132	51,495	-	487,021
Capital expenditures and acquisitions	105,722	1,042	3,117	-	109,881
Total assets	619,242	27,628	110,335	-	757,205
2006					
Revenues, net of royalties	\$3,211	\$-	\$-	\$-	\$3,211
Equity interest in Petrolifera earnings	-	389	-	-	389
Dilution gain	-	103	-	-	103
Interest and other income	416	-	8	-	424
Operating costs	831	-	-	-	831
General and administrative	956	-	-	-	956
Stock-based compensation	-	395	-	-	395
Finance charges	84	-	-	-	84
Foreign exchange loss	7	-	-	-	7
Depletion, depreciation and accretion	2,878	-	-	-	2,878
Taxes (recovery)	(358)	-	-	-	(358)
Net earnings (loss)	(1,159)	492	8	(7)	(666)
Property and equipment, net	225,965	-	47,104	-	273,069
Capital expenditures	233,735	-	67,101	-	300,836
Total assets	347,229	11,769	71,221	135	430,354

9. SUPPLEMENTARY INFORMATION

(a) Per share amounts

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

For the three months ended March 31	2007	2006
Weighted average common shares outstanding	198,119,130	154,151,848
Dilutive effect of stock options and share purchase warrants	1,888,613	6,421,936
Weighted average common shares outstanding – diluted	200,007,743	160,573,785

(b) Net change in non-cash working capital

For the three months ended March 31 (\$000)	2007	2006
Accounts receivable	\$(182)	\$(2,438)
Refinery inventories	(14,558)	-
Due from Petrolifera	109	(169)
Prepaid expenses	366	(11)
Accounts payable and accrued liabilities	14,589	11,705
Income taxes payable	(507)	-
Total	\$(183)	\$9,087

Summary of working capital changes:

(\$000)	2007	2006
Operations	\$6,922	\$4,243
Investing	(7,105)	4,844
	\$(183)	\$9,087

(c) Supplementary cash flow information

For the three months ended March 31 (\$000)	2007	2006
Interest paid	5,759	1
Income taxes paid	3,039	-
Stock-based compensation capitalized	546	210

At March 31, 2007, cash of \$66.2 million is restricted for use in paying expenditures for a designated oil sands project under the terms of the company's financing arrangements for its oil sands project.

(d) Defined benefit pension plan

In the first quarter of 2007, \$130,000 has been charged to expense in relation to MRCI's defined benefit pension plan.

10. SUBSEQUENT EVENTS

On April 27, 2007, Connacher exercised 1,714,286 warrants to acquire 1,714,286 common shares of Petrolifera Petroleum Limited for cash consideration of \$5.1 million. This transaction will increase Connacher's interest in Petrolifera to approximately 26.3% on a fully diluted basis assuming that all outstanding Petrolifera warrants are exercised.

In April 2007, the company received notice from its banker that their scheduled review of the company's conventional line of credit facility would be deferred until June 15, 2007.

CORPORATE INFORMATION

Board of Directors

Richard A. Gusella
President and Chief Executive Officer
Connacher Oil and Gas Limited, Calgary

Charles W. Berard ^(2, 4)
Chairman, Governance Committee
Chairman, Health, Safety and Environment Committee
Partner, Macleod Dixon LLP, Calgary

D. Hugh Bessell ^(1, 2, 3, 5)
Chairman, Audit Committee
Retired Deputy Chairman of KPMG, LLP

Colin M. Evans ^(1, 3, 4, 5)
Chairman, Human Resources Committee
Vice-President, Finance, Milestone Exploration Inc., Calgary

Stewart D. McGregor ^(2, 3)
Lead Director
President, Camun Consulting Corporation

W.C. ("Mike") Seth ^(1, 4, 5)
Chairman, Reserves Committee
President, Seth Consultants Ltd.

- (1) Audit Committee
- (2) Governance Committee
- (3) Human Resources Committee
- (4) Health, Safety, and Environment Committee
- (5) Reserves Committee

Officers

Richard A. Gusella
President and Chief Executive Officer

Peter D. Sametz
Executive Vice President and
Chief Operating Officer

Richard R. Kines
Vice President, Finance and
Chief Financial Officer

Timothy J. O'Rourke
Vice President, Oil Sands Operations

Stephen A. Marston
Vice President, Exploration

Cameron M. Todd
Vice President, Refining and Marketing

Steve De Maio
Vice President, Project Development

Grant D. Ukrainetz
Treasurer

Jennifer K. Kennedy
Corporate Secretary
Partner, Macleod Dixon LLP

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CUSIP number

205884

ISIN

CA20588Y1034

Refinery

1900 Tenth Street
Great Falls, Montana
59404 USA

Stock Exchange Listing

Toronto Stock Exchange
Trading symbol - CLL

Subsidiaries

Great Divide Holding Corporation
Great Divide Oil Corporation
Great Divide Pipeline Corporation
Great Divide Pipeline Limited
Connacher Finance Corporation
Montana Refining Company, Inc.
6419101 Canada Ltd.

Related Company

Petrolifera Petroleum Limited (26%)

Auditors

Deloitte & Touche LLP, Calgary

Bankers

National Bank of Canada, Calgary
BNP Paribas, Toronto and New York

Solicitors

Macleod Dixon, LLP, Calgary

Reservoir Engineers

GLJ Petroleum Consultants, Calgary

Registrar and Transfer Agent

Valiant Trust Company, Calgary
BNY Trust Company of Canada, Toronto

Abbreviations

ARTC
Alberta Royalty Tax Credit

bbls
barrels

bbl/d
barrels per day

bcf
billion cubic feet

boe
barrels of oil equivalent

boe/d
barrels of oil equivalent per day

DCF
discounted cash flow

GJ
gigajoule

mmbbls
thousand barrels

mboe
thousand barrels of oil equivalent

mcf
thousand cubic feet

mcf/d
thousand cubic feet per day

mmbbls
million barrels

mmboe
million barrels of oil equivalent

mmcf
million cubic feet

mmcf/d
million cubic feet per day

NGLs
natural gas liquids

PV
present value

WI
working interest

WTI
West Texas Intermediate