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File No. 179667

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November 22, 2006

06019025

Securities and Exchange Commission
100 F Street, N.E.
Washington, D.C. 20549

SUPPL

Dear Sir or Madam:

Re: Connacher Oil and Gas Limited (the "Company")
File No. 82-34954
Exemption Pursuant to Rule 12g-3-2(b)

We are Canadian counsel to the Company. Pursuant to Rule 12g-3-2(b) under the Securities Exchange Act of 1934, as amended, enclosed please find copy of the Company's Press Release dated November 22, 2006 as posted on SEDAR. As required pursuant to Rule 12g-3-2(b), the exemption number appears in the upper right-hand corner of each unbound page and on the first page of each bound document.

Please indicate your receipt of the enclosed by stamping the enclosed copy of this letter and returning it to the send in the enclosed self-addressed, stamped envelope.

Very truly yours,

MACLEOD DIXON LLP

L O'Neill

Jennifer K. Kenndy

JKK:lgo:encl.

cc: Mr. Richard Gusella (Via E-Mail)

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CONNACHER
OIL AND GAS LIMITED

PRESS RELEASE **November 22, 2006**

CONNACHER OIL AND GAS PROVIDES OPERATIONAL UPDATE

Calgary, Alberta – Connacher Oil and Gas Limited (CLL – TSX) hereby provides an operational update with respect to its activities, with a primary emphasis on its development project at Great Divide Pod One.

POD ONE DEVELOPMENT

The Great Divide project is steadily and systematically making progress in accordance with the development plan prepared by the Company. Recently, weather has been most cooperative and favorable for civil construction. The focus of activity has changed from pile driving to pouring concrete bases for both tanks and proposed buildings. The tank building crews are onsite ahead of the original schedule.

With respect to the main facility and well pad facilities, engineering design and the hazardous operations review ("HAZOP") are 100 percent completed, major equipment shop construction is 87 percent completed and minor equipment shop construction is estimated to be 40 percent completed.

The SAGD drilling rig Tri-City 37 is moving on to the Pad 102 drill site in preparation for the drilling of the first five of the initial 15 planned SAGD well pairs. Connacher expects to spud its first well by the end of November, 2006. A second rig will be added in early 2007 to enable the drilling program to be completed in a timely manner with both rigs scheduled to work simultaneously on Pad 101.

New pictures showing the activity and progress at Pod One are scheduled for immediate posting on the company's website at www.connacheroil.com. Click on Operations and then on the link to Great Divide to view the most recent photographs; older pictures are scheduled for removal.

GREAT DIVIDE CORE HOLE AND SEISMIC PROGRAM

Connacher attempted to secure a heli-portable drilling rig to drill additional core holes on Pod Two at Great Divide during the Fall of 2006. Unfortunately, this equipment was not available, primarily due to the limited number of such rigs and the high level of activity in the mining industry. However, assuming the recent cold temperatures in Northern Alberta persist and regulatory approvals are forthcoming in a timely manner, Connacher now anticipates being able to initiate its conventional core hole program before year end 2006, with an initial emphasis on Pod 2 evaluation. Connacher has scheduled a total of 70 core holes on its principal Great Divide leases during the winter of 2006-2007.

Favorable weather conditions have also enabled Connacher to accelerate its preparations for a planned 70 square kilometer 3D seismic program in 2007 over its principal lease blocks in the Great Divide region. The program is expected to complete 3D seismic coverage of the main lease block surrounding Pod One. The combination of the 3D seismic and core hole data should significantly enhance Connacher's assessment of expansion potential in the area over the next several years. It will also contribute to the data base available for mid-year 2007 reserve and resource evaluations. These will be undertaken once the seismic and core hole data is secured, processed, interpreted and incorporated into the company's models for the region.

Mulching and clearing of the seismic grid has been underway since October 2006 and it is anticipated seismic data acquisition will commence by early February 2007.

OVERALL ACTIVITY AT GREAT DIVIDE

With Pod One construction and development, planned seismic and planned drilling all proceeding favorably at this time, a total of 168 people are presently on site for these various aspects of the Great Divide project. At its peak in the late Winter-early Spring 2007, this staff and contractor personnel complement is expected to expand to approximately 375 people who will be engaged in facility construction, seismic acquisition and drilling. Connacher envisages a full-time staff of approximately 40 employees once the plant is commissioned and operations are underway at Pod One.

OTHER ACTIVITY

In Montana, the company's refinery is operating at just under 10,000 bbl/d of throughput with continued attractive margins. Construction of a new 150,000 barrel asphalt storage tank is proceeding on time and on budget. Welding of the second ring is presently underway and completion is targeted for the first quarter of 2007. This will provide the refinery with increased operational flexibility and better capacity utilization during the winter months when asphalt demand is reduced.

A NaHS (Sodium Hydrosulphide) project designed to improve air quality by reducing emissions is also underway and is also scheduled for a first quarter 2007 startup. The byproduct of the related process is sold and enhances the refinery's overall profitability.

Once posted, several pictures of this construction activity will also available for viewing on the website at www.connacheroil.com ; click on Operations and then the Montana Refinery link.

During the summer months of 2006, Connacher's conventional drilling activity was concentrated on oil plays at Three Hills, Alberta and at Battrum, Saskatchewan. Completions and tie-ins are starting to impact on the Company's oil production at this time. Most of the Company's conventional natural gas assets are in winter-only drilling areas, including Marten Creek, which is situated west of the oil sands region in north-central Alberta.

The company expects to mobilize drilling rigs in December 2006 for an anticipated 15-well program at Marten Creek and also has scheduled drilling in other gas-prone regions of northern Alberta during the winter of 2007. The increased availability of drilling rigs, a recent recovery in natural gas prices and seasonal access issues are all encouraging this aggressive pursuit of additional natural gas reserves and productivity, against the backdrop of the anticipated expansion of Connacher's natural gas requirements for its activity in the oil sands in the next several years.

Forward-Looking Statements: This press release contains certain forward-looking statements within the meaning of applicable securities law. Forward-looking statements are frequently characterized by words such as "plan", "expect", "project", "intend", "believe", "anticipate", "estimate. "scheduled" and other similar words, or statements that certain events or conditions "may" or "will" occur. Forward-looking statements are based on the opinions and estimates of management at the date the statements are made, and are subject to a variety of risks and uncertainties and other factors that could cause actual events or results to differ materially from those projected in the forward-looking statements. These factors include the inherent risks involved in the exploration and development of oil sands and conventional oil and natural gas properties, the uncertainties involved in interpreting drilling results and other geological data, fluctuating oil and natural gas prices, the possibility of project cost overruns or unanticipated costs and expenses, uncertainties relating to the availability and costs of financing needed in the future, unpredictability of weather conditions and other factors including unforeseen delays. As an oil sands enterprise in the development stage, Connacher faces risks, including those associated with exploration, development, approvals and the ability to access sufficient capital from external sources. Anticipated exploration and development plans relating to Connacher's properties in 2007 are subject to change depending on the results of current activities, rig availability, weather conditions, availability of required personnel as well as other considerations. For a detailed description of the risks and uncertainties facing Connacher and its business and affairs, readers should refer to Connacher's Annual Information Form for the year ended December 31, 2005. Connacher undertakes no obligation to update forward-looking statements if circumstances or management's estimates or opinions should change, unless required by law. The reader is cautioned not to place undue reliance on forward-looking statements.

For further information, contact:
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SEC RECEIVED NOV 2 8 2006 WASH. D.C. 213 SECTION

November 9, 2006

Securities and Exchange Commission
100 F Street, N.E.
Washington, D.C. 20549

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Please indicate your receipt of the enclosed by stamping the enclosed copy of this letter and returning it to the send in the enclosed self-addressed, stamped envelope.

Very truly yours,

MACLEOD DIXON LLP

LO'Neill

Jennifer K. Kenndy

JKK:lgo:encl.

cc: Mr. Richard Gusella (Via E-Mail)

CONNACHER
OIL AND GAS LIMITED

PRESS RELEASE **NOVEMBER 9, 2006**

CONNACHER OIL AND GAS REPORTS STRONG FINANCIAL RESULTS FOR Q3 AS GREAT DIVIDE OIL SANDS PROJECT MOVES CLOSER TO PRODUCTION

Calgary, Alberta – **Connacher Oil and Gas Limited (CLL – TSX)** continued to strengthen its overall operating and financial results and financial condition in the third quarter of 2006. This was achieved through growth in conventional production, strong refinery operations and timely equity and debt financing.. Meanwhile, Connacher is executing its oil sands development plans with significant progress on its great divide project. Field site preparation and construction, shop construction of major equipment and mechanical and civil design work are all advancing favorably. The first 15 steam-assisted gravity drainage ("SAGD") well pairs are to be drilled in late 2006 and early 2007.

For the third quarter of 2006, Connacher's Montana refinery showed expanded throughput, improved margins and higher utilization rates. In the meantime, conventional production in Alberta and Saskatchewan was a steady 3,256 boe/d. The company reported record cash flow from operations of $15 million for the third quarter compared with $9.5 million for the second quarter of 2006, and $2 million for the third quarter of 2005. Earnings also reached record levels at $6.8 million. These strong financial results are anticipated to continue and be expanded considerably in upcoming years when production from pod one is initiated and additional pod development and related production is introduced in a sequential manner during the balance of the decade.

Highlights for Third Quarter 2006

- Q3 2006 revenue up 3,227 percent to $103 million compared to Q3 2005 levels; nine months 2006 revenue up 2,421 percent to $167 million
- Q3 2006 cash flow of $15 million ($0.08 per share), an increase of 656 percent over 2005; nine months 2006 cash flow at $26.2 million ($0.15 per share), up 739 percent over $3.1 million last year
- Q3 2006 earnings of $6.8 million ($0.03 per share) compared to a loss in 2005; nine months 2006 earnings of $3.7 million, up 799 percent
- Q3 2006 conventional production up 265 percent to 3,256 boe/d, compared to 891 boe/d in 2005; nine months 2006 production at 2,626 boe/d, up 194 percent
- Montana refinery performs well with higher throughput, better margins
- GLJ reserve and resource estimates for Great Divide oil sands properties expanded significantly
- $30 million of new flow through equity and US$195 million of new debt facilities placed to provide capital for Great Divide and for refining operations
- Great Divide field construction well underway

Financial & Operating Highlights

	Three months ended September 30			Nine months ended September 30		
	2006	2005	% Change	**2006**	2005	% Change
FINANCIAL ($000's except per share amounts)						
Total revenue	**103,108**	3,222	3,100	**167,984**	6,818	2,364
Cash flow from operations before working capital changes [1]	**14,957**	1,978	656	**26,184**	3,120	739
Per share, basic [1]	**0.08**	0.02	300	**0.15**	0.03	400
Per share, diluted [1]	**0.08**	0.02	300	**0.14**	0.03	367
Net earnings (loss) for the period	**6,771**	(1,034)	755	**3,686**	410	799
Per share, basic	**0.03**	(0.01)	400	**0.02**	-	-
Per share, diluted	**0.03**	(0.01)	400	**0.02**	-	-
Capital expenditures and acquisitions	**41,449**	2,870	1,344	**376,564**	14,567	2,485
Cash on hand				**14,450**	67,708	(79)
Working capital (deficit) [2]				**(39,942)**	67,440	(159)
Shareholders' equity				**378,730**	113,208	235
Total assets				**527,028**	118,788	344
OPERATING						
Conventional daily sales volumes						
Crude oil - bbl/d	**1,084**	808	34	**926**	713	30
Natural gas - mcf/d	**13,028**	497	2,521	**10,198**	1,077	847
Barrels of oil equivalent - boe/d [3]	**3,256**	891	265	**2,626**	893	194
Conventional selling prices						
Oil - $/bbl	**62.53**	53.40	17	**56.83**	42.62	33
Natural gas - $/mcf	**5.33**	1.88	184	**5.58**	1.21	361
Barrels of oil equivalent - $/boe [3]	**42.16**	49.48	(15)	**41.70**	35.50	17
Refining [4]						
Sales revenue	**93,752**	-		**144,719**	-	-
Margins	**13,510**	-		**17,373**	-	-
Margins (%)	**14.4**	-		**12.0**	-	-
Common shares outstanding (000's)						
Weighted average						
Basic	**193,587**	103,851	86	**179,948**	96,018	87
Diluted	**200,572**	106,397	89	**187,135**	101,073	85
End of period						
Issued				**197,878**	134,236	47
Fully diluted				**213,491**	142,873	49

(1) Cash flow from operations before working capital changes ("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 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 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) A short term working capital deficiency exists at September 30, 2006 as part of the consideration paid for the refinery acquisition which was financed with short-term borrowings. This short term debt was repaid in October 2006.

(3) 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.

(4) Results from the date of purchase of the refinery on March 31, 2006 to September 30, 2006. In the month of April 2006 the refinery was shut down for approximately 20 days for scheduled turnaround maintenance.

Letter to Shareholders

Connacher continued to demonstrate improved financial and operating results during the third quarter of 2006. By consistently pursuing its objectives with a well-defined integration strategy, the Company's financial condition was strengthened, internally generated cash flow from operations before working capital changes grew significantly and considerable earnings were achieved. In particular, the Montana refinery was a significant performer during the reporting period as throughput was expanded, margins were improved and utilization rates were exceptional. Readers should note that cash flow from operations before working capital changes ("cash flow" or "cash flow from operations") and cash flow per share do not have standardized meanings prescribed by Canadian generally accepted accounting principles ("GAAP"). See Management's Discussion and Analysis herein.

Considerable effort during the third quarter 2006 was focused on the continued strengthening of the company's overall financial condition and capacity to fund its development program at Pod One of the Great Divide oil sands project. During the summer, $30 million of flow through equity was sold by way of a bought deal financing to secure funds for the company's ongoing core hole and 3D seismic evaluation program anticipated for the company's key Great Divide oil sands leases in the winter of 2007. A total of 70 core holes and extensive 3D coverage is scheduled for the upcoming winter drilling season.

Also, subsequent to the reporting period, Connacher completed the private placement of a US$180 million Term Loan B Facility ("Term Loan") and a US$15 million Working Capital Facility ("WC Facility") to institutional investors primarily in the United States. The Term Loan has a seven year term, nominal scheduled principal repayments and bears interest at either LIBOR plus 3.25 percent or at a Base Rate plus 2.25 percent. Under certain circumstances, limited additional periodic repayments may be required commencing in 2008. A portion of the Term Loan proceeds were used to discharge short-term indebtedness incurred to acquire the refining assets in Montana, to fund a one year debt service reserve during the construction phase at Pod One of Great Divide and to pay expenses associated with the financing. The balance of approximately US$111 million was added to working capital to be available for the construction project at Pod One.

To reduce risk, an interest rate swap establishing a rate of 8.52 percent on US$90 million of the Term Loan over its term was also completed.

The WC Facility is fully revolving, has a five year term and bears interest at either LIBOR plus three per cent or at a Base Rate plus two per cent. It was secured to provide ongoing working capital for the Montana refinery operations.

Connacher's Great Divide assets and the Montana refining assets provided security for the two facilities, which are non-recourse to Connacher. As the transaction closed after the reporting period cutoff, Connacher's nine-month balance sheet shows a working capital deficit due to the impact of the bridge loan incurred to acquire the Montana refining assets. This has since been redressed, leaving Connacher with a well-structured balance sheet, strong working capital position and growing cash flow from operations to fund other growth investment opportunities. As well, the company continues to hold an extremely valuable unencumbered equity position approaching $300 million in Petrolifera Petroleum Limited and Connacher has unutilized credit facilities deriving from the loan value of its conventional assets.

Of particular additional importance during the reporting period was the completion by GLJ Petroleum Consultants ("GLJ") of an updated report on the reserves and resources at the company's Great Divide oil sands project, situated approximately 80 kilometers (50 miles) southwest of Fort McMurray in northeastern Alberta. Connacher owns a 100 percent working interest in most of its 80,000 acre lease holding in the region, including Pod One which is presently under development. Clearly the company's oil sands properties are of considerable consequence to the value of Connacher and remain its most significant asset.

The following is a summary of the bitumen reserves and the value of future net revenues associated with Connacher's interests in the Great Divide region, as evaluated by GLJ as of September 1, 2006. The GLJ Report was prepared using assumptions and methodology guidelines outlined in the COGE

Handbook and in accordance with National Instrument 51-101. The pricing used in the forecast and constant price evaluations is set forth in the notes to the tables.

Reserves were only assigned to Pod One, in the 2P and 3P categories, although no proved reserves were assigned pending start-up of production. The study assumed 59 SAGD well pairs for the 2P case and 80 well pairs for the 3P case, with cumulative Steam Oil Ratios ("SORs") of 2.6 in both cases, but declining to 2.4 during peak production periods. The cutoffs used by GLJ for probable reserves were 13 meters of net pay for 2P reserves and 10 meters of net pay for 3P reserves.

The evaluations based on constant prices and costs utilize a net bitumen price derived from pricing data posted as of June 30, 2006. Although June 30, 2006 prices are utilized, production of bitumen is not anticipated to commence until mid-2007. Accordingly, if product prices from which the net bitumen price is derived decline, then the present value of future net revenue associated with reserves and the associated reserves volumes will be less than those estimated in the GLJ Report and such reductions may be significant. All evaluations of future revenue are after the deduction of royalties, all capital/development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenues contained in the following tables do not necessarily represent the fair market value of Connacher's reserves. There is no assurance that the forecast and constant price and cost assumptions contained in the GLJ Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the GLJ Report. The recovery and reserve estimates of Connacher's properties described herein are estimates only. The actual reserves on Connacher's oil sands properties may be greater or less than those calculated.

RESERVES AND NET PRESENT VALUE OF FUTURE NET REVENUE BASED ON FORECAST PRICES AND COSTS (6)

	Bitumen		Before Deducting Income Taxes Discounted At					After Deducting Income Taxes(8) Discounted At				
	Gross(1) (mbbl)	Net(1) (mbbl)	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)
Proved Plus Probable Undeveloped(2)(3)(5)	79,632	71,059	1,040	502	261	138	69	720	342	171	83	33
Proved Plus Probable Plus Possible Undeveloped (2)(3)(4)(5)	111,629	98,539	1,680	688	331	174	93	1,154	467	218	108	50

RESERVES AND NET PRESENT VALUE OF FUTURE NET REVENUE BASED ON CONSTANT PRICES AND COSTS (7)

	Bitumen		Before Deducting Income Taxes Discounted At					After Deducting Income Taxes(8) Discounted At				
	Gross(1) (mbbl)	Net(1) (mbbl)	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)
Proved Plus Probable Undeveloped(2)(3)(5)	79,632	66,357	1,809	973	581	374	253	1,243	665	394	250	165
Proved Plus Probable Plus Possible Undeveloped (2)(3)(4)(5)	111,805	92,523	2,601	1,211	674	423	286	1,780	823	452	278	182

Notes:

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

(2) "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is 90% likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(3) "Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

(4) "Possible" reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

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

(6) The pricing assumptions used in the GLJ Report with respect to values of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

	Heavy Oil	Natural Gas	Inflation Rate	Exchange Rate
	Proxy (12 API) at Hardisity ($Cdn/bbl)	Alberta Spot Gas ($/mcf)	%/year	US$/$Cdn
Forecast				
2007	42.50	6.50	2.0	0.890
2008	40.00	8.25	2.0	0.890
2009	37.25	8.10	2.0	0.890
2010	36.00	7.75	2.0	0.890
2011	37.25	7.35	2.0	0.890
2012	38.25	7.15	2.0	0.890
2013	39.25	7.30	2.0	0.890
2014	39.75	7.45	2.0	0.890
2015	40.75	7.65	2.0	0.890
2016	41.50	7.80	2.0	0.890
Thereafter	+2%/yr	+2%/yr	2.0	0.890

(7) The product prices used in the constant price and cost evaluations in the GLJ Report were as follows: West Texas Intermediate crude oil at Cushing, Oklahoma: $73.93 US$D/bbl; Alberta Spot gas at AECO-C: $5.14/mmbtu; and light crude oil at Edmonton: $85.28/bbl and a bitumen wellhead price of $44.34/bbl.

(8) Estimations of future income tax expenses included in the GLJ Report relate solely to estimated unclaimed costs and tax losses, tax credits and allowances in respect of the Great Divide project.

Oil and Gas Resources

Only Pod One has sufficient well and seismic control to warrant the assignment of reserves. The other five pods have insufficient drilling density, seismic mapping or project definition to be categorized as reserves at this time. Additional drilling and seismic activity could result in upgrading these to reserve status over time. In the interim, a range of contingent resources was assigned to reflect uncertainties. The GLJ Report provided calculations of Contingent Resources comprised of "Low Estimate Resources (> 15 meter Pay) - higher certainty" together with "Best Estimate Resources (> 13 meter Pay) - likely certainty" and "High Estimate Resources (> 10 meter Pay) - lower certainty". Low Estimate recoverable resources are comprised of mapped original oil-in-place assigned to Pod One (> 15 meter Pay) with a lower recovery factor than are applied to the estimate of 2P reserves. Best Estimate Resources are comprised of 2P remaining recoverable reserves together with an estimate of recoverable resources attributable to five other pods on Connacher's lands. High Estimate Resources (lower certainty) include 3P recoverable reserves at Pod One together with recoverable resources at the other five pods on Connacher's acreage, but with a larger areal extent and a higher recovery factor than attributable under the Best Estimate Category. In addition to Contingent resources described above, volumes were also estimated for prospective or undiscovered resources No prospective resources were assigned to the low estimate category.

Calculations of the present value of the future net revenue from remaining recoverable contingent and prospective resources were included in the GLJ Report. The determination of production forecasts and economic potential followed a similar methodology to that of the reserves evaluation cases. Indicative future net revenues for these resource categories were prepared using scoping estimates as detailed design estimates have not been prepared.

GLJ forecasts the Low Estimate Reserves and Contingent Resources case production start-up to occur in mid-2007 with a peak rate of 10,400 barrels of oil per day achieved by 2014; the Best Estimate Reserve and Contingent Resources case forecasts production start-up to occur in mid-2007 and a peak rate of 20,200 barrels of oil per day is achieved by 2017; and the High Estimate Reserve and Contingent Resources case forecasts production start-up to occur in mid-2007 with a peak rate of 25,400 barrels of oil per day achieved by 2017. Utilizing GLJ's forecast for the Reserves, Contingent and Prospective Resources results in a Best Estimate Reserves and Total Resources case of production start-up in mid-2007 with a peak rate of 29,900 barrels of oil per day achieved by 2017 while the High Estimate Reserves and Total Resources production starts up in mid-2007 with a peak rate of 40,200 barrels of oil per day achieved by 2012.

SUMMARY OF RESERVES AND RESOURCES VALUES BASED ON FORECAST PRICES AND COSTS(6)

	Low Estimate Reserves Plus Contingent Resources	Best Estimate Reserves Plus Contingent Resources	High Estimate Reserves Plus Contingent Resources	Low Estimate Reserves + Total Resources	Best Estimate Reserves + Total Resources	High Estimate Reserves + Total Resources
ORIGINAL OIL-IN-PLACE (mbbl)	167	396	483	167	545	855
DEVELOPED ORIGINAL OIL-IN-PLACE (mbbl)	150	356	459	150	491	819
MARKETABLE RESERVES						
Bitumen (mbbl)						
Gross Reserves(1)	62,949	185,260	261,567	62,949	254,427	459,162
Net Reserves(1)	57,077	166,189	233,227	57,077	228,573	406,225
BEFORE TAX PRESENT VALUE (MM$)						
0%	708	2,530	3,728	708	3,305	6,999
5%	369	998	1,428	369	1,349	2,522
10%	194	427	604	194	576	1,049
15%	96	177	256	96	229	459
20%	37	52	87	37	56	183
AFTER TAX PRESENT VALUE (MM$)						
0%	495	1,729	2,539	495	2,251	4,750
5%	251	662	945	251	885	1,666
10%	124	263	374	124	345	655
15%	52	87	132	52	103	249
20%	8	-1	14	8	-17	59

SUMMARY OF RESERVES AND RESOURCES VALUES BASED ON CONSTANT PRICES AND COSTS(7)

	Low Estimate Reserves Plus Contingent Resources	Best Estimate Reserves Plus Contingent Resources	High Estimate Reserves Plus Contingent Resources	Low Estimate Reserves + Total Resources	Best Estimate Reserves + Total Resources	High Estimate Reserves + Total Resources
MARKETABLE RESERVES						
Bitumen (mbbl)						
Gross Reserves(1)	63,140	185,481	286,943	63,140	254,770	459,337
Net Reserves (1)	53,167	155,163	239,435	53,168	213,269	380,579
BEFORE TAX PRESENT VALUE (MM$)						
0%	1,375	4,126	6,400	1,374	5,608	10,520

5%	804	1,900	2,876	804	2,638	4,342
10%	501	1,009	1,485	500	1,392	2,150
15%	326	588	843	326	794	1,202
20%	218	362	507	218	474	722
AFTER TAX PRESENT VALUE (MM$)						
0%	948	2,814	4,358	948	3,818	7,150
5%	551	1,282	1,932	551	1,772	2,913
10%	339	669	976	339	914	1,413
15%	216	379	536	216	504	764
20%	140	223	305	139	283	436

Connacher's current focus is primarily on the construction program at Pod One in Great Divide. Significant progress has already been made, reflecting the effectiveness of the company's modular approach and efficient pre-planning for the construction phase. As at October 30, 2006 the company's engineering and procurement consultants have confirmed that major equipment shop construction is over 87 percent completed, mechanical and civil design work was over 85 percent completed and other components of the project were well-advanced. Field operations including civil preparation of the plant site are estimated to be 25 percent complete, including installation of piles for storage tanks to be field constructed in early 2007 is on schedule. Drilling plans are also advancing to enable the first 15 steam-assisted gravity drainage ("SAGD") well pairs to be drilled later this year and in early 2007.

Connacher is also actively recruiting new full-time employees for its anticipated Great Divide production operations and has successfully commenced its hiring program. We welcome all new employees associated with the Great Divide Pod One project and also welcome our developing and productive relationship with all our consultants and service and supply companies who will assist Connacher in completing the project in the most timely and cost-effective manner possible. Connacher is proud of the prospect of being in the position of having reduced the timeline for projected startup at Great Divide from first purchase of its acreage in 2004 to less than four years, which it believes is a record pace of execution.

Outlook

The outlook for Connacher is buoyant, even against the background of weakened commodity prices for both crude oil and natural gas. The company is well-financed and has been able to maintain its 100 percent ownership of its Great Divide SAGD oil sands project without undue dilution of its equity, while securing medium-term limited recourse debt financing to fund a significant portion of its prospective capital outlays. Connacher believes this to be far preferable to short-term bank financing with its vagaries or to diluting its interest in the project through farmout or joint venture. The company has retained control of its own destiny to the long term benefit of its common shareholders.

In 2007 focus will continue to be on Great Divide although other important work will be carried out on the company's conventional acreage and at its Montana refinery. A capital budget approaching $250 million is envisaged for next year, with approximately 80 percent directed to both Pod One development and startup and to anticipating continued evaluation of additional pods and undeveloped acreage in the Great Divide region. It is hoped a formal applications for the next pod at Great Divide will be submitted early in 2007. Conventional activity will focus on drilling for natural gas at Marten Creek and other selected regions in northern Alberta, oil development drilling at Three Hills, Alberta and ongoing projects at Battrum, Saskatchewan. It is also anticipated over $16 million will be invested in the Montana refining operation during 2007.

Management's Discussion and Analysis ("MD&A")

The following is dated as of November 8, 2006 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 and nine months ended September 30, 2006 and 2005 as contained in this interim report and the MD&A and audited financial statements for the years ended December 31, 2005 and 2004 as contained in the company's 2005 annual report. The unaudited consolidated financial statements for the three and nine months ended September 30, 2006 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. Information contained in this report contains forward-looking information based on current expectations, estimates and projections of future production, capital expenditures and available sources of financing. It should be noted that 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, 2005, 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 fluctuation, currency controls, 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
CONVENTIONAL PRODUCTION, PRICING AND REVENUE

	Three months ended September 30			Nine months ended September 30		
	2006	2005	% Change	**2006**	2005	% Change
Conventional daily production / sales volumes						
Crude oil – bbl/d	**1,084**	808	34	**926**	713	30
Natural gas – mcf/d	**13,028**	497	2,521	**10,198**	1,077	847
Combined – boe/d	**3,256**	891	265	**2,626**	893	194
Product pricing ($)						
Crude oil – per bbl	**62.53**	53.40	17	**56.83**	42.62	33
Natural gas – per mcf	**5.33**	1.88	184	**5.58**	1.21	363
Combined – per boe	**42.16**	49.48	(15)	**41.70**	35.50	17
Conventional oil and gas revenues ($000's)	**12,325**	4,055	204	**29,892**	8,655	245

Conventional oil and gas revenues in the third quarter of 2006 were three times higher than in the third quarter of 2005.

The acquisition of Luke Energy Ltd. on March 16, 2006 was the most significant factor in this increase, as natural gas sales volumes increased more than 26 times from last year on a third quarter comparison. Natural gas selling prices are also up almost three times from 2005, when Argentinean gas pricing adversely affected corporate natural gas prices.

Increased crude oil production and sales volumes from new wells drilled in southwest Saskatchewan (net of the impact of ceasing to consolidate Petrolifera's results) and increased world oil pricing also contributed to the increase in conventional oil and natural gas revenues in the current quarter.

Natural gas and crude oil sales are now more evenly balanced, contributing 52 percent and 48 percent, respectively, of total year to date 2006 conventional revenues.

ROYALTIES ON CONVENTIONAL PETROLEUM AND NATURAL GAS SALES

For the three months ended September 30	2006		2005	
	Total	**Per boe**	Total	Per boe
Royalties ($000's)	**$3,134**	**$10.72**	$961	$11.73
Percentage of petroleum and natural gas revenue	**25.4%**		24%	

For the nine months ended September 30	2006		2005	
	Total	**Per boe**	Total	Per boe
Royalties ($000's)	**$7,318**	**$10.21**	$2,018	$8.28
Percentage of petroleum and natural gas revenue	**24.6%**		23%	

Royalties represent charges against production or revenue by governments and landowners.

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.

OPERATING EXPENSES AND NETBACKS – CONVENTIONAL

Company Netbacks [1]
For the nine months ended September 30

($000's)	2006		2005		% Change	
	Total	**Per boe**	Total	Per boe	Total	Per boe
Average daily production (boe/d)	**2,626**		893		194	
Petroleum and natural gas revenue	**29,892**	**41.70**	$8,655	$35.50	345%	17.4%
Interest & other income	**690**	**0.96**	181	0.74	381	29.7
Royalties	**(7,318)**	**(10.21)**	(2,018)	(8.28)	362	23.3
Net revenue	**23,264**	**32.45**	6,818	27.96	341	16.1
Operating costs	**(5,693)**	**(7.94)**	(1,799)	(7.38)	320	7.6
Company netback – conventional operations	**17,571**	**24.51**	$5,019	$20.58	350	19.1

(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 of Connacher with performance measures and that provides shareholders and investors with a measurement of Connacher's efficiency and its ability to fund future growth through capital expenditures.

Operating Netbacks by Product
For the nine months ended September 30, 2006

($000's)	Crude oil		Natural gas	
	Total	Per bbl	Total	Per mcf
Average daily production	926 bbl/day		10,198 mcf/d	
Total revenue	14,369	56.83	15,524	5.58
Royalties	(3,518)	(13.90)	(3,800)	(1.36)
Operating costs	(2,008)	(7.95)	(3,685)	(1.32)
Operating netback	8,843	34.98	8,039	2.90

For the third quarter of 2006 operating costs of $2.4 million were 279 percent higher than in the same prior year period, commensurate with increases in daily sales volumes. On a per unit basis, operating costs increased by eight percent to $7.94 per boe. The increase in operating costs, both absolutely and on a per unit basis, reflects the company's increased production and sales volumes in a higher cost environment.

Primarily as a result of higher product prices, operating netbacks per boe for the first nine months of 2006 increased 19 percent to $24.51 per boe compared to $20.58 in the first nine months of 2005.

REFINING REVENUES AND MARGINS

On March 31, 2006, Connacher completed the acquisition of the refining assets of Montana Refining Company. The assets acquired included the refinery and certain inventory including refined products. The results reported herein are for the period from April 1, 2006. In April, 2006 the refinery was shut down for 20 days for scheduled "turnaround" maintenance. Since resuming refining operations after the turnaround, certain increased efficiencies have occured, and throughput daily volumes have been increased.

The operating results of the refinery since its acquisition to September 30, 2006 are summarized below.

	For the three months ended		For the year to date
	June 30, 2006	September 30, 2006	to September 30, 2006
Refinery throughput			
Crude charged (bbl/d) (1)	6,864	9,613	8,239
Refinery production (bbl/d) (2)	6,932	10,392	8,662
Sales of produced refined products (bbl/d)	6,266	12,220	9,243
Sales of refined products (bbl/d) (3)	7,384	12,680	10,032
Refinery utilization (%) (4)	83%	101%	92%

(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.

Feedstocks			
Sour crude oil (%)	98%	92%	94%
Other feedstocks and blends (%)	2%	8%	6%
Total	100%	100%	100%
Refining sales revenue ($000's)	$50,967	$93,752	$144,719
Refining - crude oil and operating costs ($000's)	47,104	80,242	127,346
Refining margin ($000's)	$3,863	$13,510	$17,373
Refining margin (%)	7.6%	14.4%	12.0%

Sales of produced refined products (based on volumes)			
Gasolines (%)	27%	30%	29%
Diesel fuels (%)	15%	15%	15%
Jet fuels (%)	3%	4%	4%
Asphalt (%)	50%	49%	49%
LPG and other (%)	5%	2%	3%
Total	100%	100%	100%
Average per barrel sold			
Refining sales revenue	$75.85	$80.37	$78.83
Less refining - crude oil and operating costs	70.10	68.78	69.36
Refining margin	$5.75	$11.59	$9.47

Below are reconciliations to the Consolidated Statement of Income for refining sales and refining - crude oil and operating costs. Due to rounding, some amounts may not calculate exactly.

Reconciliation of refined product sales to refining sales revenue

Average sales price per barrel sold	$75.85	$80.37	$78.83
Sales of refined products (bbl/d)	7,384	12,680	10,032
Number of days in period	91	92	183
Refined product sales ($000's)	$50,967	$93,752	$144,719

Reconciliation of average cost of products per barrel sold to refining - crude oil and operating costs

Average cost of products per barrel sold	$70.10	$68.73	$69.36
Sales of refined products (bbl/d)	7,384	12,680	10,032
Number of days in period	91	92	183
Refining - crude oil and operating costs ($000's)	$47,104	$80,242	$127,346

The Montana Refining Company acheived outstanding results in the third quarter. Quarterly revenues increased 83% to $93.8 million, reflecting increased throughput, increased asphalt sales from inventory and increased product prices. Due to continuing process optimization the crude capacity of the refinery has now been increased to 9,500 bbl/d. During the quarter, refinery utilization was 101% and the operation ran without downtime. Operations in the previous quarter were limited to 83% utilization due to a maintenance turnaround conducted in April. Net refining margin has improved to $13.5million or $11.59/barrel, an increase of 250% over second quarter results. In addition to increased prices and throughput, average product costs have decreased thereby improving margins.

Due to the demand of the summer paving season, asphalt sales volumes and revenues generated approximately one-half of the refinery's third quarter revenues. During this same period asphalt production was augmented by sales from inventory. As sales volumes and revenues decline to lower levels through the fourth and first quarters, inventory builds to supply the demand of the subsequent paving season.

EQUITY INTEREST IN PETROLIFERA EARNINGS

Connacher accounts for its 27 percent equity investment in Petrolifera Petroleum Limited ("Petrolifera") on the equity method basis of accounting. In the comparative period, Petrolifera was consolidated with Connacher. Connacher's equity interest share of Petrolifera's earnings in the third quarter of 2006 was $4.6 million and $7.1 million for the year to date.

DILUTION GAIN

Since November 2004, the company's equity interest in Petrolifera has been diluted as a result of Petrolifera issuing common shares. In November 2004, the company's equity interest was reduced from 100 percent to 61 percent; in March 2005 it was reduced to 40 percent; in late 2005, it was further reduced to 33 percent and through out 2006 it was reduced to 27 percent. These reductions resulted in a dilution gain to the company of $3,000 in the year to date for 2006 (2005 - $3 million gain).

INTEREST AND OTHER INCOME

In the third quarter of 2006, the company earned interest of $165,000 (2005 - $128,000) on excess funds invested in secure short-term investments, and $690,000 for the nine months ended September 30, 2006 (2005 - $181,000).

GENERAL AND ADMINISTRATIVE EXPENSES

In the third quarter of 2006, general and administrative ("G&A") expenses were $605,000 compared to $553,000 in the third quarter of 2005. The current year amount was impacted by reclassifying $585,000 of costs associated with refining operations to operating costs from G&A and the impact of capitalizing G&A costs directly associated with the development of the company's oil sands project. For the 2006 year for date, G&A costs of $815,000 have been capitalized (2005 - $62,000).

STOCK-BASED COMPENSATION

In the year to date, non-cash stock-based compensation costs of $9.5 million were recorded (2005 - $941,000). These charges reflect the fair value of all stock options granted and vested in each period. Of this amount, $6.7 million was expensed (2005 - $941,000) and $2.8 million was capitalized (2005 – nil). A portion of the amount expensed is included in refining operating costs. The year over year increase reflects the growth and success of the corporation and the expanded equity base as a result of prior sales of common shares from treasury.

FINANCE CHARGES AND FOREIGN EXCHANGE

Certain costs relating to establishing the company's banking facilities (bankers' fees, legal costs, etc.) are being deferred and amortized over the periods to which the banking facilities relate. In the year to date, deferred financing charges of $1.9 million (2005 - nil) and interest of $2.3 million (2005 - $112,000) were expensed.

The translation of foreign currency denominated assets and liabilities in the year to date resulted in a foreign exchange loss of $201,000 and a gain of $30,000 for the first nine months of 2005. The company's main exposure to foreign currency risk relates to a US$51,000,000 bridge loan, its US-based refining business and to the pricing of its crude oil sales, which are denominated in US dollars.

DEPLETION, DEPRECIATION AND ACCRETION ("DD&A")

The amounts reported for DD&A represent depletion charges in respect of the company's conventional petroleum and natural gas properties, depreciation of its refinery, depreciation of its administrative assets, accretion expense related to future abandonment charges estimated in respect of conventional and refining abandonment liabilities, and amortization of refinery turnaround maintenance costs.

Depletion expense is calculated using the unit-of-production method based on total estimated proved reserves; the refinery and administrative assets are depreciated over their estimated useful lives. The present value of the company's future abandonment liabilities are reported on the company's balance sheet and during the period to abandonment, this balance is accreted to the estimated full future cost.

The table below summarizes the DD&A charges for 2006 and 2005.

	Three months ended September 30		Nine months ended September 30	
($000's)	**2006**	2005	**2006**	2005
Depletion of conventional assets	**8,350**	1,380	**20,140**	3,649
Depreciation of refinery assets	**622**	-	**1,244**	-
Amortization of turnaround costs	**643**	-	**876**	-
Other depreciation	**222**	212	**336**	257
Accretion	**80**	21	**212**	93
Total	**9,917**	1,613	**22,808**	3,999

On a per unit basis, depletion has increased to $28.00 per boe from $15.00 per boe in the first nine months of 2005. The increase in depletion expense (both absolute and per unit) is the result of increased depletable assets due to the Luke acquisition and the cost of new wells drilled.

Capital costs of $94 million (2005 – $10 million) related to the Great Divide oil sands project, which is in a pre-production state, have been excluded from depletable costs. Additionally, undeveloped land acquisition costs of $12.7 million (2005 – $2.3 million) were excluded from the depletion calculation, while future development costs of $1.6 million (2005 - $2 million) for proved undeveloped reserves were included in the depletion calculation.

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 2006 or 2005.

TAXES
The current income tax provision of $4.2 million for the first nine months of 2006 primarily relates to income taxes expected to be payable by MRC from its US-based refining business, and Canadian provincial capital taxes.

The future income tax recovery of $2.1 million for the first nine months of 2006 primarily represents the impact of recently enacted federal and provincial income tax rate reductions.

At September 30, 2006 the company had approximately $200 million of deductible resource pools, $15 million of deductible financing costs and $9 million of non-capital losses which do not expire before 2009.

NET EARNINGS
In the third quarter of 2006, Connacher generated a profit of $6.8 million ($0.03 per basic and diluted shares outstanding) as a result of significantly expanded business activities, compared to a loss of $1 million ($0.01 loss per share) in the third quarter of 2005.

For the first nine months of 2006 the company reported a profit of $3.7 million ($0.02 per basic and diluted share outstanding). This compares to net earnings of $410,000 or $nil per basic and diluted share for the same 2005 period.

SHARES OUTSTANDING
For the nine months ended September 30, 2006, the weighted average number of common shares outstanding was 180 million (2005 - 96 million) and the weighted average number of diluted shares outstanding, as calculated by the treasury stock method, was 213 million (2005 - 143 million). The substantial increase in shares outstanding period over period reflects the equity financings completed by the company and the treasury shares issued as partial consideration for the Luke and refinery acquisitions.

As at November 9, 2006, the company had the following securities issued and outstanding:
- 197,878,015 common shares; and
- 15,545,535 share purchase options.

LIQUIDITY AND CAPITAL RESOURCES
A short term working capital deficiency existed at September 30, 2006 as part of the consideration paid for the refinery acquisition was financed with cash and short-term borrowings. In early April 2006 the company drew US$51 million on a bridge loan facility to partially fund the acquisition of the Montana refinery assets, which closed on March 31, 2006. This bridge loan was repaid in full on October 20, 2006 from the proceeds of a US$180 million term loan ("TLB") facility that was fully drawn on that date. The primary purpose of the TLB is to fund the total estimated remaining costs necessary to develop the company's first oil sands project at Great Divide in northern Alberta ("Pod One"). After also depositing US$14 million into an account to fund the estimated interest costs during the course of completing the Pod One project, and after paying US$4 million in costs to complete the transaction, the balance of TLB proceeds of US$111 million will be used solely to fund the total estimated remaining costs necessary to complete Pod One.

The TLB has a seven year term. Its principal is amortized by one percent per year commencing in 2008. Additional principal payments will depend on debt to cash flow ratios. Principal payments on the TLB are not expected to be significant in the first six years. One half of the TLB floating interest rate payments were swapped at an all-in fixed rate of 8.516 percent and one half of the TLB bears interest of London Inter-Bank Offered Rate ("LIBOR") plus 3.25 percent or at US Prime Lending Rate ("Base Rate") plus 2.25 percent.

On October 20, 2006 the company also secured a US$15 million revolving line of credit ("LOC") to fund the working capital requirements of the refinery in Great Falls, Montana that was acquired in March 2006. The LOC has a five year term and bears interest at LIBOR plus three percent or at Base Rate plus two percent.

The TLB and the LOC are secured by a debenture and mortgage agreements covering all of the assets of the refinery and all of the company's interest in the Great Divide oil sands. The TLB and LOC debts are non-recourse to the company's conventional petroleum and natural gas assets or its investment holding in Petrolifera Petroleum Limited.

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 boes) 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.

Management believes that Connacher has adequate liquidity, anticipated cash generation, unused credit and credit capacity to conduct its operations and to meet its obligations in accordance with its financial plan and budget. The company maintains no off-balance sheet financial instruments.

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

	Three months ended September 30		Nine months ended September 30	
($000's)	**2006**	2005	**2006**	2005
Net earnings (loss)	**$6,771**	$(1,034)	**$3,686**	$410
Items not involving cash:				
Depletion, depreciation and accretion	**9,917**	1,613	**22,808**	3,999
Stock-based compensation	**1,478**	610	**6,672**	941
Financing charges	**(398)**	-	**1,910**	-
Future income tax provision (recovery)	**1,414**	600	**(2,159)**	766
Future employee benefits	**128**	-	**253**	-
Foreign exchange (gain) loss	**163**	11	**201**	(30)
Lease inducement amortization	**(15)**	-	**(45)**	-
Dilution (gain) loss	**49**	-	**(3)**	(3,020)
Income applicable to non-controlling interests	**-**	124	**-**	-
Equity interest in Petrolifera earnings	**(4,550)**	54	**(7,139)**	54
Cash flow from operations before working capital changes	**$14,957**	$1,978	**$26,184**	$3,120

For the third quarter of 2006, cash flow was $15 million ($0.08 per basic and diluted share), 656 percent higher than the $2 million ($0.02 per basic and diluted share) reported in the third quarter of 2005.

CAPITAL EXPENDITURES AND FINANCING ACTIVITIES

For the third quarter of 2006, capital expenditures totaled $41 million and $376 million for the first nine months. A breakdown of the expenditures for the first nine months of 2006 follows:

($000's)	Three months ended September 30 **2006**	2005	Nine months ended September 30 **2006**	2005
Acquisition of Luke	**$463**	$-	**$204,643**	$-
Acquisition of refinery	**307**	-	**66,333**	-
Minor property acquisitions	**2,789**	477	**7,217**	1,560
Oil sands expenditures	**31,466**	720	**83,562**	6,061
Conventional oil and gas expenditures	**5,733**	1,673	**13,862**	6,946
Refinery expenditures	**690**	-	**948**	-
	$41,449	$2,870	**$376,564**	$14,567

Oil sands expenditures include exploratory core hole drilling, seismic, lease acquisition and facility costs. In 2006, 31 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.

Conventional oil and gas gross and net wells drilled in 2006 are as follows:

	Quarter One	Quarter Two	Quarter Three	Total
Conventional wells drilled (100% working interest)	3	4	6	13

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 approximate 87 percent working interest in its conventional properties, providing the company with operational and timing controls.

The company has recently entered into a 10 year office lease agreement committing it to pay approximately $1.6 million per year commencing in July 2007.

Great Divide Oil Sands Project, Northern Alberta

The company holds a 99.7 percent working interest in 79,360 acres of oil sands leases in the Great Divide region of northern Alberta. To date, the focus has been on an approximate 2,000 acre tract ("Pod One") on which approximately $100 million has been invested to acquire the oil sands leases, to delineate the oil bearing reservoir and for certain facilities related to this project. Total costs for Pod One are expected to approximate $240 million including contingencies and certain capitalized items. Having received regulatory approvals, full development of Pod One has been initiated. Additionally, the company continues to delineate further oil bearing reserves on a portion of the remaining 77,000 acres at Great Divide.

Recent Financings

In February 2006 the company entered into financing commitment letters with BNP Paribas, a major international bank, for the following lending facilities:

(i) a $45 million reserve-based loan and a $10 million revolving operating loan to finance conventional petroleum and natural gas projects in Canada. This facility was established on March 16, 2006; and
(ii) a US$51 million bridge loan to fund a significant portion of the acquisition of the Montana refinery. This facility was established on March 31, 2006.

In October 2006, Connacher secured a US$180 million term loan facility and a US$15 million revolving working capital loan facility for the refinery. A portion of the term loan was used to repay the US$51 million bridge loan. The surplus term loan proceeds are to finance all remaining forecast capital expenditures on Pod One of the company's Great Divide Oil Sands project.

In February 2006, the company issued 19,047,800 common shares at $5.25 per share for gross proceeds of $100 million to fund exploration and development activities associated with conventional crude oil and natural gas activities and the Great Divide Oil Sands project, for general corporate purposes, for working capital and to possibly partially fund the acquisition of Luke Energy Ltd. Proceeds of the financing were utilized as follows:

($000's)	As stated at the time of financing	As actually applied
Gross proceeds	$100,000	$100,000
Underwriters commission and issue costs	6,250	6,250
Available for exploration and development, general corporate purposes, for working capital and to possibly fund a portion of the Luke acquisition	$93,750	$93,750

In September 2006, the company issued 5,714,300 common shares on a "flow-through" basis at $5.25 per common share for gross proceeds of $30 million to fund exploration activities to further delineate the company's oil sands properties through the drilling of additional core holes and shooting 3D seismic. Proceeds of the financing were utilized as follows:

($000's)	As stated at the	As actually
Gross proceeds	$30,000,075	$30,000,075
Underwriters commission and issue costs	2,075,000	1,883,000
	$27,925,075	$28,117,075

Refer also to the "Liquidy and Capital Resources," above, for a discussion of the US$180 million and US$15 million debt facilities entered into in October 2006.

Acquisition of Luke Energy Ltd. ("Luke")

In December 2005 the company entered into a binding letter agreement to purchase, by way of a Plan of Arrangement, all of the shares of Luke for a cash consideration of $2.31 per share plus 0.75 of a Connacher common share for each Luke common share. On March 15, 2006 the Luke shareholders voted to approve the arrangement and on March 16, 2006 the arrangement was completed by the payment in total of $91.5 million cash and the issuance of 29.7 million Connacher common shares from treasury.

Luke is now a wholly-owned subsidiary of Connacher and produces approximately 2,800 boe/d (90 percent natural gas), largely at Marten Creek in northern Alberta. It operates most of its high working interest properties. This production was considered strategic to Connacher, as it provides a physical hedge to its initial requirements for natural gas to create steam for the company's (approved) SAGD oil sands project at Great Divide. Based on current Luke production volumes and anticipated results of further development programs, the Luke purchase could also provide surplus volumes for sale in the marketplace or meet possible future Connacher requirements at Great Divide.

Acquisition of Refining Assets in Montana

On March 31, 2006, the company acquired an 8,300 bbl/d refinery located in Great Falls, Montana, USA for approximately US$55 million, comprised of cash and one million Connacher common shares which were 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. ("MRC"). Its continued profitability will depend largely on the spread between market prices for refined petroleum products and the cost of crude oil.

MRC'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, MRC sells a high grade asphalt into the local market. MRC's principal expenses relate to costs of products sold and operating expenses.

In April 2006, MRC completed a scheduled plant "turnaround" maintenance program of its refinery facilities. Such turnarounds are normally scheduled every two to five years. Turnaround costs are capitalized and amortized over the period to the next scheduled turnaround.

With minimal additional anticipated capital investment, MRC would be capable of producing low sulfur gasoline ("LSG") as required by September 2008. Management is also studying changes necessary to comply by September 2010 with ultra low sulfur diesel ("ULSD") requirements. MRC will also be required to make investments of approximately US $2 million before 2010 for the installation of certain state of the art pollution control equipment.

The above mentioned regulatory compliance items, including the ULSD and LSG requirements, or other presently existing or future environmental regulations, could cause management to make additional capital investments beyond those described above and/or incur additional operating costs to meet applicable requirements.

On October 22, 2004, the American Jobs Creation Act of 2004 was signed into law. Among other things, the Act creates tax incentives for small refiners preparing to produce ULSD. The Act provides an immediate deduction of 75% of certain costs paid or incurred to comply with the ULSD standards and a tax credit based on ULSD production for up to 25% of those costs. Management intends to utilize these incentives when it is required to make these required expenditures.

NEW CRITICAL ACCOUNTING POLICIES ADOPTED BY CONNACHER

MRC's financial results are reported in accordance with Canadian GAAP and are consolidated with Connacher's other business units. The preparation of MRC'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. Connacher's management considers the following new MRC accounting policies to be the most critical to understanding the judgments that are involved and the uncertainties that could impact on the company's results of operations, financial condition and cash flows.

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. Net realizable value is determined using current estimated selling prices.

Deferred Maintenance Costs

MRC's 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 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. The costs of turnarounds are recorded as deferred charges and are amortized over the expected periods of benefit.

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 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 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 discontinued cash flows and fair values of assets require subjective assumptions with regard to future operating results and actual results could differ from those estimates.

RISK MANAGEMENT - MRC

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. MRC'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.

MRC'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, MRC 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, the company has recently issued parental guarantees and indemnifications on behalf of MRC. This is considered to be in the normal course of business. The company has not entered into any off-balance sheet arrangements.

EMPLOYEE BENEFITS PLANS

As a consequence of the refinery acquisition and related employment of refinery personnel, the company's new US subsidiary, MRC, adopted new employee future benefit plans with effect from March 31, 2006.

A new non-contributory defined benefit retirement plan covers only MRC's employees from March 31, 2006. MRC's policy is to make regular contributions in accordance with the funding requirements of the United States Employee Retirement Income Security Act of 1974. Benefits are to be based on the employee's years of service and compensation.

MRC also established new defined contribution (US tax code "401(k)") plans that cover all of its employees from March 31, 2006. The company's contributions are based on employees' compensation and partially match employee contributions.

BUSINESS RISKS

Other than as noted above for "Risk Management - MRC," there was no material change in the company's risks or risk management activities since December 31, 2005. Connacher's risk management activities are conducted according to policies and guidelines established by the Board of Directors. Readers should refer to Connacher's 2005 AIF and the risk management section of the 2005 annual MD&A.

IMPACT OF NEW ACCOUNTING PRONOUNCEMENTS

The company has assessed new and revised accounting pronouncements that have been issued but that are not yet effective and has determined that the following may have a significant impact on the company.

Beginning with the year ending December 31, 2007 the company will be required to adopt, if applicable, the Canadian Institute of Chartered Accountants ("CICA") Section 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. Requirements for hedge accounting have been further clarified. Although Connacher is in the process of evaluating the impact of these standards, the company does not expect the Financial Instruments and Hedges standards to have a material impact on its Consolidated Financial Statements.

Over the next five 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 Stands ("IFRS") over the next five years. The company continues to monitor and assess the impact of the convergence of Canadian GAAP with IFRS.

OUTLOOK

The company's business plan anticipates continued 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. Timing for development and first production from the Great Divide Oil Sands Project is subject to availability of the component equipment, access to skilled personnel and availability of drilling rigs. Additional financing may be required for the Great Divide Oil Sands Project and the company's conventional petroleum and natural gas assets.

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

QUARTERLY RESULTS

	2004	2005 [3]				2006 [5]		
Three Months Ended	Dec 31	Mar 31	Jun 30	Sept 30 [3]	Dec 31	Mar 31	June 30	Sept 30
Financial Highlights ($000 except per share amounts)- Unaudited								
Total revenue	1,987	1,857	2,796	3,222	3,542	4,446	64,614	103,108
Cash flow from operations before working capital changes [1]	471	265	877	1,978	1,238	1,725	9,499	14,957
Basic, per share [1]	0.01	-	0.01	0.02	0.01	0.01	0.05	0.08
Diluted, per share [1]	0.01	-	0.01	0.02	0.01	0.01	0.05	0.08
Net earnings (loss)	(150)	1,673	(230)	(1,034)	582	(666)	(2,419)	6,771
Basic, per share	-	0.02	-	(0.01)	-	-	(0.01)	0.03
Diluted, per share	-	0.02	-	(0.01)	-	-	(0.01)	0.03
Capital expenditures and acquisitions	3,954	6,047	5,649	2,870	2,241	300,836	34,280	41,449
Proceeds on disposal of PNG properties	(49)	-	-	-	-	-	-	-
Bank debt	-	-	250	-	-	17,600	70,365	62,380
Working capital surplus (deficiency)	3,549	5,588	854	67,440	75,427	(11,061)	(42,483)	(39,942)
Cash on hand (net debt)	3,914	8,286	2,629	67,708	75,511	(4,527)	7,505	14,450
Shareholders' equity	40,375	41,079	41,090	113,081	129,108	337,584	340,639	378,730
Operating Highlights - Conventional								
Production / sales volumes								
Natural gas - mcf/d	1,290	1,328	1,416	497	86	2,600	15,172	13,028
Crude oil - bbl/d	646	629	702	808	775	689	1,026	1,084
Equivalent - boe/d [2]	861	850	938	891	789	1,122	3,554	3,256
Pricing								
Crude oil - $/bbl	30.68	30.02	41.23	53.40	41.54	40.93	61.45	62.53
Natural gas - $/mcf	1.29	1.18	0.99	1.88	7.55	6.34	5.66	5.33
Selected Highlights - $/boe [2]								
Weighted average sales price	24.93	24.04	32.35	49.48	41.61	39.83	41.88	42.16
Other income	0.15	0.24	0.41	1.57	7.15	4.20	0.04	0.55
Royalties	4.64	4.82	8.06	11.73	7.76	8.02	10.43	10.72
Operating costs	7.98	7.01	7.42	7.69	8.90	8.24	7.63	7.99
Netback [4]	12.47	12.45	17.28	31.63	32.09	27.77	23.86	24.00
Operating Highlights - Refining								
Refining production – bbl/d							6,932	10,392
Net sales per barrel sold ($)							75.85	80.37
Refining margin ($)							5.75	11.59
Common Share Information								
Shares outstanding at end of period (000's)	89,627	92,753	93,013	134,236	139,940	191,257	191,924	197,878
Weighted average share outstanding for the period								
Basic (000's)	50,908	91,189	92,875	103,851	136,071	154,152	191,672	193,587
Diluted (000's)	53,329	94,197	95,555	106,397	142,507	160,574	198,931	200,572
Volume traded during quarter (000's)	25,256	40,486	16,821	180,848	100,246	148,184	80,347	48,849
Common share price ($)								
High	0.80	1.22	1.05	2.69	4.20	6.07	5.05	4.55
Low	0.29	0.49	0.68	0.76	1.09	3.47	3.10	3.09
Close (end of period)	0.55	0.93	0.82	2.54	3.84	4.95	4.30	3.60

(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 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 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) 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. Refer to MD&A for netbacks by product type.

(5) Reflects the financial and operating results relating to the acquisition of Luke following closing on March 16, 2006, and the Montana refinery subsequent to its acquisition on March 31, 2006.

CONSOLIDATED BALANCE SHEETS
Connacher Oil and Gas Limited
(Unaudited)

($000's)	September 30, 2006	December 31, 2005
ASSETS		
CURRENT		
Cash and cash equivalents	**$14,450**	$75,511
Accounts receivable	**35,474**	1,605
Refinery inventories (Note 6)	**18,635**	-
Prepaid expenses	**2,309**	407
Due from Petrolifera (Note 5)	**-**	221
	70,868	77,744
Property, plant and equipment	**330,586**	45,242
Investment in Petrolifera (Note 5)	**17,638**	10,496
Other assets	**4,275**	256
Future income tax asset	**-**	1,075
Goodwill (Note 3)	**103,661**	-
	$527,028	$134,813
LIABILITIES		
CURRENT		
Accounts payable	**$48,408**	$2,316
Bank debt (Note 7)	**62,380**	-
Due to Petrolifera (Note 5)	**22**	-
	110,810	2,316
Future employee benefits	**251**	-
Asset retirement obligations (Note 8)	**6,363**	3,108
Deferred credits	**236**	281
Future income tax liability	**30,638**	-
	148,298	5,705
SHAREHOLDERS' EQUITY		
Share capital and contributed surplus (Note 9)	**374,288**	127,033
Cumulative translation adjustment	**(1,319)**	-
Retained earnings	**5,761**	2,075
	378,730	129,108
	$527,028	$134,813

CONSOLIDATED STATEMENTS OF OPERATIONS AND RETAINED EARNINGS
Connacher Oil and Gas Limited
(Unaudited)

($000's, except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
REVENUE				
Petroleum and natural gas revenue, net of royalties	**$9,191**	$3,094	**$22,575**	$6,637
Refining sales	**93,752**	-	**144,719**	-
Interest and other income	**165**	128	**690**	181
	103,108	3,222	**167,984**	6,818
EXPENSES				
Petroleum and natural gas operating costs	**2,393**	631	**5,693**	1,799
Refining – crude oil and operating costs	**80,242**	-	**127,346**	-
General and administrative	**605**	553	**2,780**	1,805
Stock-based compensation (Note 9)	**1,139**	610	**6,334**	941
Finance charges	**993**	36	**4,231**	112
Foreign exchange loss (gain)	**163**	11	**201**	(30)
Depletion, depreciation and accretion	**9,917**	1,613	**22,808**	3,999
	95,452	3,454	**169,393**	8,626
Earnings (loss) before taxes and other items	**7,656**	(232)	**(1,409)**	(1,808)
Current income tax provision (recovery)	**3,972**	24	**4,206**	(18)
Future income tax provision (recovery)	**1,414**	600	**(2,159)**	766
	5,386	624	**2,047**	748
Earnings (loss) before other items	**2,270**	(856)	**(3,456)**	(2,556)
Equity interest in Petrolifera earnings (loss) (Note 5)	**4,550**	(54)	**7,139**	(54)
Dilution gain (loss) (Note 5)	**(49)**	-	**3**	3,020
Non-controlling interests (Note 5)	**-**	(124)	**-**	-
NET EARNINGS (LOSS)	**6,771**	(1,034)	**3,686**	410
RETAINED EARNINGS (DEFICIT), BEGINNING OF PERIOD	**(1,010)**	2,655	**2,075**	1,211
RETAINED EARNINGS, END OF PERIOD	**$5,761**	$1,621	**$5,761**	$1,621
EARNINGS (LOSS) PER SHARE (Note 11)				
Basic	**0.03**	(0.01)	**0.02**	-
Diluted	**0.03**	(0.01)	**0.02**	-

CONSOLIDATED STATEMENTS OF CASH FLOW
Connacher Oil and Gas Limited
(Unaudited)

($000's)	Three months ended September 30		Nine months ended September 30	
	2006	2005	**2006**	2005
Cash provided by (used in) the following activities:				
OPERATING				
Net earnings (loss)	**$6,771**	$(1,034)	**$3,686**	$410
Items not involving cash:				
Depletion, depreciation and accretion	**9,917**	1,613	**22,808**	3,999
Stock-based compensation	**1,478**	610	**6,672**	941
Financing charges	**(398)**	-	**1,910**	-
Future employee benefits	**128**	-	**253**	-
Future income tax provision (recovery)	**1,414**	600	**(2,159)**	766
Foreign exchange loss (gain)	**163**	11	**201**	(30)
Dilution (gain) loss	**49**	-	**(3)**	(3,020)
Lease inducement amortization	**(15)**	-	**(45)**	-
Loss applicable to non-controlling interests	**-**	124	**-**	-
Equity interest in Petrolifera (earnings) losses	**(4,550)**	54	**(7,139)**	54
Cash flow from operations before working capital changes	**14,957**	1,978	**26,184**	3,120
Change in non-cash working capital (Note 11 (b))	**8,636**	3,182	**(24,335)**	3,075
	23,593	5,160	**1,849**	6,195
FINANCING				
Issue of common shares, net of share issue costs	**28,270**	70,506	**123,558**	72,138
Issue of shares by Petrolifera, net of share issue costs	**-**	-	**-**	6,228
Deferred financing costs	**548**	-	**(2,245)**	-
Increase (decrease) in bank debt	**(7,985)**	(250)	**62,380**	-
	20,833	70,256	**183,693**	78,366
INVESTING				
Acquisition of Luke Energy Ltd. (Note 3)	**(38)**	-	**(92,677)**	-
Acquisition of refining assets (Note 4)	**767**	-	**(61,273)**	-
Acquisition and development of oil and gas properties	**(41,752)**	(2,870)	**(105,589)**	(14,567)
Acquisition of other assets	**-**	-	**(5,185)**	-
Change in non-cash working capital (Note 11 (b))	**3,603**	(1,489)	**17,294**	28
	(37,420)	(4,359)	**(247,430)**	(14,539)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**7,006**	71,057	**(61,888)**	70,022
EFFECT OF EXCHANGE RATE CHANGES ON CASH AND CASH EQUIVALENTS	**(61)**	-	**827**	-
IMPACT ON CASH RESULTING FROM DECONSOLIDATION OF PETROLIFERA (Note 5)	**-**	(6,228)	**-**	(6,228)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	**7,505**	2,879	**75,511**	3,914

CASH AND CASH EQUIVALENTS, END OF PERIOD	**14,450**	67,708	14,450	67,708

SUPPLEMENTARY INFORMATION – (Note 11)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
Connacher Oil and Gas Limited

Period ended September 30, 2006
(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. In Canada and in the United States through a wholly owned subsidiary, Montana Refining Company, Inc. ("MRC") the company is in the business of exploring, 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 NEW ACCOUNTING POLICIES

The interim Consolidated Financial Statements have been prepared following the same accounting policies and methods of computation as the annual audited Consolidated Financial Statements for the year ended December 31, 2005. 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, 2005.

As a result of the March 2006 acquisition of Luke Energy Ltd. and the March 2006 purchase of refining assets, the company has adopted the following new significant accounting policies.

Seasonality of refining operations

Due to the demand of the summer paving season, asphalt sales volumes and revenues generated approximately one-half of the refinery's third quarter revenues. During this same period asphalt production was augmented by sales from inventory. As sales volumes and revenues decline to lower levels through the fourth and first quarters, inventory builds to supply the demand of the subsequent paving season.

Refinery inventories

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 changed its method of accounting from LIFO to the average cost method. The change did not have a significant impact and no adjustment was recorded. Net realizable value is determined using current estimated selling prices.

Long-lived refining assets

Depreciation and amortization is calculated based on estimated useful lives and salvage values. Long-lived assets are 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.

Goodwill

Goodwill is the excess purchase price over the fair value of identifiable assets and liabilities acquired. Goodwill impairment is assessed annually at year end, or more frequently as economic events dictate, by comparing its fair value to its carrying value, including goodwill. If the fair value is less than its carrying value, a goodwill impairment loss is recognized as the excess of the carrying value of the goodwill over the fair value of the goodwill.

Foreign currency translation

The company has assessed the operations of MRC 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 expense 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 currency translation adjustment in shareholders' equity.

Pension costs
The company's newly acquired subsidiary, MRC, has a defined benefit pension plan commencing March 31, 2006 for certain of its employees. Pension expenses for the plan amount to $253,000 in the current year to date.

Revenue recognition
Refined product sales and related costs of sales are recognized when products are shipped and title has passed to customers. All revenues are reported inclusive of shipping and handling costs incurred and billed on to customers and exclusive of excise taxes. Shipping and handling costs incurred are reported in costs of products sold.

Depreciation of refining assets
Depreciation is calculated by the straight-line method over the estimated useful lives of the assets, primarily 10 to 20 years for refining facilities, three to five years for transportation vehicles, 10 to 40 years for buildings and improvements and 7 to 30 years for other fixed assets.

Cost classifications
Costs of products sold include the cost of crude oil, other feedstocks, blendstocks and purchased finished products, inclusive of transportation costs. To provide the desired crude oil to the refinery, crude oil is purchased from producers and other petroleum companies through crude oil buy/sell exchange contracts. Operating expenses include direct costs of labor, maintenance materials and services, utilities, marketing expenses and other direct operating costs. General and administrative expenses include compensation, professional services and other support costs.

Deferred maintenance costs
Refinery units require regular major maintenance and repairs which are commonly referred to as "turnarounds". Catalysts used in certain refinery processes also require regular "changeouts". The required frequency of the maintenance varies by unit and by catalyst, but generally is every two to five years. Turnaround costs are deferred and amortized over the period until the next scheduled turnaround. Other repairs and maintenance costs are expensed when incurred.

Environmental liabilities
Environmental liabilities are recorded when site restoration and environmental remediation and cleanup obligations are either known or considered probable and can be reasonably estimated. Recoveries of environmental costs through insurance, indemnification arrangements or other sources are recognized to the extent such recoveries are considered probable.

Derivative instruments
Derivative instruments would be recognized as either assets or liabilities in the balance sheet and measured at their fair value. Changes in the derivative instrument's fair value would be recognized in earnings unless specific hedge accounting criteria are met. Currently, the company has no derivative instruments.

3. ACQUISITION OF LUKE ENERGY LTD.
The company completed the acquisition of Luke Energy Ltd. ("Luke") on March 16, 2006. Final closing adjustments have yet to be determined and some costs of the deal have been estimated. Consequently, the preliminary purchase equation is estimated as follows:

	($000's)
Net assets acquired:	
Petroleum and natural gas assets	153,755
Goodwill	103,661
Asset retirement obligations (Note 8)	(2,109)
Working capital	(19,308)
Future income tax liability	(31,356)
Net assets acquired	204,643
Consideration paid:	
Cash	92,677
Shares (Note 9)	111,966
	204,643

Included in the working capital deficit are capital costs paid or payable arising from Luke's winter drilling program and for transaction costs incurred by Luke. Included in cash consideration paid are transaction costs of $2 million.

The value of the share consideration paid was determined by reference to the market value of the company's shares at the time of announcing the acquisition.

4. ACQUISITION OF REFINING ASSETS

On March 31, 2006 the company acquired all of the assets of a refinery in Great Falls, Montana. Final closing adjustments have yet to be determined and some costs of the deal have been estimated. Consequently, the purchase equation is estimated as follows.

	($000's)
Net assets acquired:	
Refining assets	$46,337
Inventory	19,996
Net assets acquired	$66,333
Consideration paid:	
Cash	$61,273
Shares (Note 9)	5,060
	$66,333

Included in cash consideration paid are transaction costs of $2 million.

The value of the share consideration paid was determined by reference to the market value of the company's shares at the time of announcing the acquisition.

The purchase agreement commits the vendor to resolve any environmental liabilities arising over the next five years for environmental matters existing at the purchase date.

As a means to facilitate the expeditious transition of the ongoing refinery business, MRC assumed all of the ongoing purchase and sales contracts with suppliers and customers of the refinery. These contracts are all short-term in nature and necessitated some guarantees from Connacher, all considered to be in the normal course of business.

5. INVESTMENT IN PETROLIFERA PETROLEUM LIMITED ("PETROLIFERA")

The company records its investment in Petrolifera on an equity basis. Until the end of the second quarter of 2005 this investment was consolidated.

Under the terms of a Management Services Agreement with Petrolifera, Connacher provides management, operational, accounting and general and administrative services necessary or appropriate to manage and operate Petrolifera. The fee for this service is $15,000 per month until May 2007. The agreement may be immediately terminated for performance failure by the aggrieved party or upon 30 days prior written notice by Connacher, or by mutual agreement.

Dilution gains are recognized upon changes to Connacher's equity interest in Petrolifera as they occur. In 2006, Petrolifera share purchase rights and share purchase warrants were exercised by other investors resulting in a reduction of Connacher's equity interest in Petrolifera to 27 percent at September 30, 2006. The exercise of these rights and warrants generated a dilution loss for the year to date, in the amount of $3,000.

6. REFINING INVENTORIES

($000's)	September 30, 2006
Crude oil	1,883
Other raw materials and unfinished products [1]	1,045
Refined products [2]	13,736
Process chemicals [3]	1,030
Repairs and maintenance supplies and other	941
	18,635

(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.

7. BANK LOANS

As at September 30, 2006 the company had available a $45 million reserve-based revolving loan ("RBL facility") and a $10 million revolving operating loan to finance conventional petroleum and natural gas projects in Canada. These facilities have a renewable one year term and are secured by a fixed and floating charge debenture in the principal amount of $500 million. Interest at bank prime plus ¼ percent is to be charged on amounts borrowed. At September 30, 2006 the company had drawn $5.5 million on the RBL facility.

In early April 2006 the company drew US $51 million on a bridge loan facility to partially fund the acquisition of the Montana refinery assets, which closed on March 31, 2006. The loan did bear interest at London Inter-Bank Offered Rate ("LIBOR") + ½ percent for the first 90 days (adjusted for subsequent quarterly periods), was secured by a US$500 million demand debenture and pledge agreement. This bridge loan was repaid in full on October 20, 2006 from the proceeds of a US$180 million term loan ("TLB") facility that was fully drawn on that date.

The TLB has a seven year term. Its principal is amortized by one percent per year commencing in 2008. Additional principal payments will depend on debt to cash flow ratios. Principal payments on the TLB are not expected to be significant in the first six years. One half of the TLB floating interest payments were swapped at an all-in fixed rate of 8.516 percent and one half of the TLB bears interest of LIBOR plus 3.25 percent or at US Prime Lending Rate ("Base Rate") plus 2.25 percent.

On October 20, 2006 the company also secured a US$15 million revolving line of credit ("LOC") to fund the working capital requirements of the refinery in Great Falls, Montana that was acquired in

March 2006. The LOC has a five year term and bears interest at LIBOR plus three percent or at Base Rate plus two percent.

The TLB and the LOC are secured by a debenture and mortgage agreements covering all of the assets of the refinery and all of the company's interest in the Great Divide oil sands. The TLB and LOC debts are non-recourse to the company's conventional petroleum and natural gas assets or its investment holding in Petrolifera.

8. ASSET RETIREMENT OBLIGATIONS

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligation associated with the retirement of petroleum and natural gas properties and facilities.

($000's)	**Nine months ended September 30, 2006**	Year ended December 31, 2005
Asset retirement obligations, beginning of period	**$3,108**	$2,905
Liabilities incurred	**366**	301
Liabilities acquired (Note 3)	**2,109**	-
Liabilities settled with Petrolifera deconsolidation	**-**	(442)
Liabilities disposed	**-**	(24)
Change in estimates	**568**	203
Accretion expense	**212**	165
Asset retirement obligations, end of period	**$6,363**	$3,108

9. SHARE CAPITAL AND CONTRIBUTED SURPLUS

Authorized

The authorized share capital is comprised of 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's)
Share Capital:		
Balance, December 31, 2005	139,940,4	$125,071
Issued for cash in private placement (a)	19,047,80	100,001
Issued for cash in public offering (b)	5,714,300	30,000
Issued for Luke acquisition (Note 3)	29,699,28	111,966
Issued for refinery acquisition (Note 4)	1,000,000	5,060
Issued upon exercise of options (c)	982,365	905
Issued upon exercise of warrants (d)	1,493,820	881
Share issue costs		(8,272)
Tax effect of share issue costs		2,924
Tax effect of expenditures renounced pursuant to the 2005 flow-through		(5,448)
Balance, Share Capital, September 30, 2006	197,878,0	363,088

Contributed Surplus:	
Balance, December 31, 2005	1,962
Fair value of share options granted (b)	9,453
Assigned value of options exercised	(215)
Balance, Contributed Surplus,September 30, 2006	11,200
Total Share Capital and Contributed Surplus:	
December 31, 2005	127,033
September 30, 2006	374,288

(a) Private placement – 2006

In March 2006 the company issued from treasury 19,047,800 common shares at $5.25 per share on a private placement basis.

(b) 2006 flow-through common share issue

In September 2006, the company issued from treasury 5,714,300 common shares on a flow-through basis at $5.25 per share. The company has agreed to renounce the related resource expenditures of $30 million to the flow-through investors. The company has until December 31, 2007 to incur the eligible resource expenditures. As at September 30, 2006 none of these expenditures have been incurred.

(c) Stock options granted

A summary of the company's outstanding stock option grants, as at September 30, 2005 and 2006 and changes during those periods are presented below:

	2006		2005	
	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price
		$		$
Outstanding, beginning of period	**8,592,600**	**1.49**	3,988,600	0.53
Granted	**8,002,300**	**4.91**	3,501,000	1.31
Expired	**-**	**-**	(70,000)	0.55
Exercised	**(982,365)**	**0.70**	(564,500)	0.57
Outstanding, end of period	**15,612,535**	**3.29**	6,855,100	0.93
Exercisable, end of period	**5,626,198**	**2.47**	2,832,200	0.85

All stock options have been granted for a period of five years. Of the 8,002,300 options granted in 2006, 6,020,000 vest one-third immediately, one-third one year after grant and one-third two years after grant. The remaining 1,982,300 vest one-third one year after grant, one-third two years after grant and one-third three years after grant. The table below summarizes unexercised stock options.

Range of Exercise Prices	Number Outstanding	**Weighted Average Remaining Contractual Life at September 30, 2006**
$0.20 - $0.99	3,179,235	**2.9**
$1.00 - $1.99	2,001,000	**3.7**
$2.00 - $3.99	3,036,000	**4.2**
$4.00 - $5.56	7,396,300	**4.5**
	15,612,535	

In 2006 a compensatory non-cash charge of $9,454,000 (2005 - $941,000) was recorded, reflecting the fair value of stock options granted and vested during the period. Of this current amount, $6,334,000 (2005 - $941,000) was expensed to G&A, $338,000 was charged to refining operating costs and $2,782,000 (2005 – nil) 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:

	2006	2005
Risk free interest rate	**4.1%**	3.0%
Expected option life (years)	**3**	3
Expected volatility	**49%**	53%

The weighted average fair value at the date of grant of all options granted in the first nine months of 2006 was $1.81 per option (2005 - $0.47).

(d) Share purchase warrants

A summary of the company's outstanding share purchase warrants, as at September 30, 2005 and 2006 and changes during the periods are presented below:

	2006	2005
Outstanding, beginning of period	**1,493,820**	5,300,525
Exercised	**(1,493,820)**	(3,504,005)
Expired	**-**	(15,000)
Outstanding, end of period	**-**	1,781,520

(e) Flow-through shares (2005)

Effective December 31, 2005, the company renounced $15 million of resource expenditures to flow-through investors. The related tax effect of $5,448,000 on those expenditures was recorded in 2006. As at September 30, 2006, the company had incurred all of the required expenditures related to these flow-through shares.

10. SEGMENTED INFORMATION

In Canada the company is in the business of exploring, producing and marketing conventional petroleum and natural gas and has recently commenced exploration and development of bitumen in the oil sands of northern Alberta. Prior to the de-consolidation of Petrolifera in 2005 (Note 5) it also conducted a conventional petroleum and natural gas business in Argentina. The significant aspects of these operating segments are presented below. Included in total Canadian conventional assets is the company's carrying value of its investment in Petrolifera.

Three months ended September 30	Canada		Argentina	USA	Canada	
($000's)	Conventional	Oil Sands	Conventional	Refining	Administrative	Total
2006						
Revenues, net of royalties	9,191	-	-	93,752	-	102,943
Equity interest in Petrolifera earnings	-	-	-	-	4,550	4,550
Dilution gain (loss)	-	-	-	-	(49)	(49)
Interest and other income	18	-	-	147	-	165
Operating costs	2,393	-	-	80,242	-	82,635
General and administrative	-	-	-	-	605	605
Stock-based compensation	-	-	-	-	1,139	1,139
Finance charges	501	-	-	(977)	1,469	993
Foreign exchange loss (gain)	83	-	3	(27)	104	163
Depletion, depreciation and accretion	8,430	-	-	1,265	222	9,917
Taxes (recovery)	(135)	-	-	5,120	401	5,386
Net earnings (loss)	(2,063)	-	(3)	8,276	561	6,771

Property and equipment	189,932	96,488	-	43,710	456	330,586
Goodwill	103,661	-	-	-	-	103,661
Capital expenditures and acquisitions	8,651	31,465	-	998	335	41,449
Total assets	308,091	95,914	251	105,067	17,705	527,028
2005						
Revenues, net of royalties	2,948	-	146	-	-	3,094
Equity interest in Petrolifera loss	-	-	-	-	(54)	(54)
Interest and other income	123	-	5	-	-	128
Operating costs	575	-	56	-	-	631
General and administrative	-	-	31	-	522	553
Stock-based compensation	-	-	-	-	610	610
Finance charges	32	-	4	-	-	36
Foreign exchange loss (gain)	20	-	(9)	-	-	11
Depletion, depreciation and accretion	1,532	-	63	-	18	1,613
Taxes (recovery)	726	-	(102)	-	-	624
Non-controlling interest	-	-	(124)	-	-	(124)
Net earnings (loss)	186	-	(16)	-	(1,204)	(1,034)
Property and equipment	31,210	11,326	-	-	672	43,208
Capital expenditures	1,917	720	215	-	18	2,870
Total assets	106,654	11,326	-	-	808	118,788

Nine months ended September 30	Canada		Argentina	USA	Canada	
($000's)	Conventional	Oil Sands	Conventional	Refining	Administrative	Total
2006						
Revenues, net of royalties	22,575	-	-	144,719	-	167,294
Equity interest in Petrolifera Earnings	-	-	-	-	7,139	7,139
Dilution gain	-	-	-	-	3	3
Interest and other income	431	-	-	259	-	690
Operating costs	5,693	-	-	127,346	-	133,039
General and administrative	-	-	-	-	2,780	2,780
Stock-based compensation	-	-	-	-	6,334	6,334
Finance charges	801	-	7	1,954	1,469	4,231
Foreign exchange loss (gain)	115	-	9	(27)	104	201
Depletion, depreciation and accretion	20,353	-	-	2,119	336	22,808
Taxes	(3,294)	-	-	4,935	406	2,047
Net earnings (loss)	(662)	-	(16)	8,651	(4,287)	3,686
Property and equipment	189,932	96,488	-	43,710	456	330,586
Goodwill	103,661	-	-	-	-	103,661
Capital expenditures and acquisitions	225,276	83,562	-	67,281	445	376,564
Total assets	308,091	95,914	251	105,067	17,705	527,028
2005						
Revenues, net of royalties	5,744	-	893	-	-	6,637
Equity interest in Petrolifera earnings	-	-	-	-	(54)	(54)
Dilution gain (loss)	-	-	-	-	3,020	3,020
Interest and other income	159	-	22	-	-	181
Operating costs	1,480	-	319	-	-	1,799

General and administrative	-	-	229	-	1,576	1,805
Stock-based compensation	-	-	-	-	941	941
Finance charges	66	-	46	-	-	112
Foreign exchange loss (gain)	3	-	(33)	-	-	(30)
Depletion, depreciation and accretion	3,443	-	493	-	63	3,999
Taxes (recovery)	784	-	(36)	-	-	748
Net earnings (loss)	127	-	(103)	-	386	410
Property and equipment	31,210	11,326	-	-	672	43,208
Capital expenditures	6,666	6,061	1,767	-	73	14,567
Total assets	106,654	11,326	-	-	808	118,788

11. SUPPLEMENTARY INFORMATION

(a) Per share amounts

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

For the three months ended September 30	**2006**	2005
Weighted average common shares outstanding	**193,587**	103,851
Dilutive effect of stock options and stock purchase warrants	**6,985**	2,546
Weighted average common shares outstanding – diluted	**200,572**	106,397

For the nine months ended September 30		
Weighted average common shares outstanding	**179,948**	96,018
Dilutive effect of stock options and stock purchase warrants	**7,187**	5,055
Weighted average common shares outstanding – diluted	**187,135**	101,073

(b) Net change in non-cash working capital

For the three months ended September 30	**2006**	2005
Accounts receivable	**(595)**	275
Due from (to) Petrolifera	**248**	-
Non-controlling interest in Petrolifera loss	**-**	3,201
Prepaid expenses	**122**	(170)
Refinery inventories	**9,392**	-
Accounts payable	**3,072**	(1,613)
Total	**12,239**	1,693

Summary of working capital changes:

Operations	**8,636**	3,182
Investing	**3,603**	(1,489)
	12,239	1,693

For the nine months ended September 30		
Accounts receivable	**(29,802)**	(333)
Due from (to) Petrolifera	**243**	-
Non-controlling interest in Petrolifera loss	**-**	3,612
Prepaid expenses	**(1,134)**	(94)
Refinery inventories	**1,361**	-
Accounts payable	**22,291**	(82)
Total	**(7,041)**	3,103

Summary of working capital changes:		
Operations	(24,335)	3,075
Investing	17,294	28
	(7,041)	3,103

(c) Supplementary cash flow information

For the three months ended September 30	**2006**	2005
Interest paid	**931**	17
Income taxes paid	**-**	-
Stock-based compensation capitalized	**840**	-

For the nine months ended September 30		
Interest paid	**2,322**	50
Income taxes paid	**-**	-
Stock-based compensation capitalized	**2,782**	-

12. RESTATEMENT

As a result of a recent adjustment proposed by Canada Revenue Agency to resource tax pools respecting assets acquired in 2002, the December 31, 2002 balance of property and equipment was increased by $850,000 and the future income tax asset balance was reduced by $850,000. Additional depletion of $216,000 ($127,000 net of tax) for 2002 and 2003 was recorded as an adjustment to the opening balance of retained earnings for 2005. There was no change to net earnings for 2005.

Forward-Looking Statements: This press release contains certain forward-looking statements within the meaning of applicable securities law. Forward-looking statements are frequently characterized by words such as "plan", "expect", "project", "intend", "believe", "anticipate":, "estimate" and other similar words, or statements that certain events or conditions "may" or "will" occur. All information relating to reserves, resources and future net-revenue constitute forward-looking statements and are based upon the independent evaluation of GLJ. Forward-looking statements are based on the opinions and estimates of management at the date the statements *are made, and are subject to a variety of risks and uncertainties and other factors that could cause actual events or results to differ materially from those projected in the forward-looking statements. These factors include the inherent risks involved in the exploration and development of oil sands properties, the uncertainties involved in interpreting drilling results and other geological data, fluctuating oil prices, the possibility of project cost overruns or unanticipated costs and expenses, uncertainties relating to the availability and costs of financing needed in the future and other factors including unforeseen delays. As an oil sands enterprise in the development stage, Connacher faces risks, including those associated with exploration, development, approvals and the ability to access sufficient capital from external sources. Anticipated exploration and development plans relating to Connacher's properties in 2007 are subject to change. For a detailed description of the risks and uncertainties facing Connacher and its business and affairs, and for definitions of proved, probable and possible reserves and contingent and prospective resources, readers should refer to Connacher's Annual Information Form for the year ended December 31, 2005. Connacher undertakes no obligation to update forward-looking statements if circumstances or management's estimates or opinions should change, unless required by law. The reader is cautioned not to place undue reliance on forward-looking statements. Reports are based on assumptions which means that future net revenues listed in this release do not represent fair market value.*

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