

## Q2

## Second Quarter Report 2005 Highlights

- Great Divide reserves elevated to probable status per GLJ report
- Probable bitumen reserves for Pod One of 69.6 million barrels - 10 percent PW \$226 million; 8 percent PW \$290 million; other resources also recognized
- Great Divide EUB application nearing completion
- Total corporate proved and probable reserves now 73 million boe with 10 percent PW of \$267 million, up 1,814 percent by volume and 703 percent by value
- Successful Canadian drilling results in oil production increases - now over 825 bbl/d, up 56 percent since January 2005
- Petrolifera signs license for Block 106 (Maranon) in Peru , prepares to sign for Block 107 (Ucayali) - total 5 million acres

## Financial &amp; Operating Highlights

(\$000's except per share amounts)	Three months ended June 30			Six months ended June 30		
	2005	2004	% Change	2005	2004	% Change
<b>FINANCIAL</b>						
Total revenue	2,796	3,556	(21)	4,653	6,846	(32)
Cash flow from operations before working capital changes <sup>(1)</sup>	877	516	70	1,142	1,460	(22)
Per basic and diluted share <sup>(1)</sup>	0.01	0.01	-	0.01	0.03	(67)
Net earnings (loss)	(230)	(1,268)	82	1,443	(1,957)	-
Per share, basic and diluted	-	(0.03)	-	0.02	(0.04)	-
Capital expenditures	5,649	2,602	117	11,697	12,994	(10)
Cash on hand (net debt)				2,629	(32,012)	-
Shareholders' equity				41,217	20,933	97
Total assets				52,432	60,531	(13)
Common shares outstanding (000's)						
Weighted average						
Basic	92,875	47,042	97	92,037	46,553	98
Diluted	95,555	48,496	97	94,717	49,150	93
End of Period						
Issued				93,013	47,368	96
Fully diluted				100,331	54,590	84
<b>OPERATING</b>						
Daily production / sales volumes						
Crude oil - bbl/d	702	1,004	(30)	666	932	(29)
Natural gas - mcf/d	1,416	1,860	(24)	1,372	2,064	(34)
Barrels of oil equivalent - boe/d <sup>(2)</sup>	938	1,314	(29)	894	1,276	(30)
Prices						
Oil - \$/bbl						
Canada	40.70	28.74	42	35.00	29.18	20
Argentina	44.99	43.41	4	42.47	42.80	(1)
Total	41.23	29.46	40	35.96	29.90	20
Natural gas - \$/mcf						
Canada	6.06	6.57	(8)	5.87	6.08	(3)
Argentina	0.86	0.86	-	0.80	0.53	51
Total	0.99	5.11	(81)	1.08	4.73	(77)
Barrels of oil equivalent - \$/boe <sup>(2)</sup>	32.35	29.74	9	28.42	29.49	(4)
Operating netback - \$/boe <sup>(2)</sup>	17.28	12.53	38	15.00	13.12	14

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

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

# Letter to Shareholders

Continuing favorable progress at Great Divide, the expansion of Petrolifera and a reactivated and successful drilling program at Battrum, Saskatchewan were the dominant features of Connacher's activity in the first half of 2005.

## GREAT DIVIDE

At the Company's Great Divide, Alberta oil sands project, a successful 3D seismic program over a significant portion of Pod One was completed with high quality results. Interpretation of the data confirmed the geological model which had been developed from analysis of the cores and logs secured from the 19 core holes drilled on or around Pod One. Results confirmed the belief that development of Pod One was a commercially viable option. A considerable effort was exerted in the preparation of the extensive and detailed application to proceed with development of a 10,000 bbl/d project at Great Divide. This initiative is now virtually complete and should be submitted to regulators in a matter of days. Connacher has already initiated the consultation process with stakeholders who might be impacted by the project.

In conjunction with the application and analysis process, Connacher commissioned an independent evaluation of the reserves and resources associated with its Great Divide holdings. Subsequent to the reporting period, the results of the study by Gilbert Laustsen Jung Associates Ltd. ("GLJ"), independent petroleum engineers of Calgary, Alberta, dated July 29, 2005 with an effective date of September 1, 2005, were released. The report and estimates were prepared in compliance with the Canadian Oil and Gas Evaluation Handbook ("COGEH") and with National Instrument 51-101 – Standards for Disclosure of Oil and Gas Activities ("NI 51-101").

As a consequence of Pod One becoming a project for which regulatory approval was being sought, GLJ was able to recognize a significant portion of Pod One reserves in the probable reserve category, while continuing to recognize significant additional Pod One reserves in the possible category. Reserves will not be recognized as "proved" until production is underway. GLJ assigned 69.6 million probable ("2P") recoverable barrels of bitumen to Pod One and 108.3 million barrels of probable and possible reserves ("3P"). Using their July 2005 full-year escalated pricing for Great Divide crude, GLJ estimated the probable reserves for Pod One alone to have a 10 percent pre-tax present value, after deducting forecast royalties, operating costs, capital and abandonment and restoration charges over the project life exceeding 25 years to be \$226.3 million (approximately \$2.40 per basic common share). The probable and possible reserves ("3P") were estimated to have a 10 percent present value, calculated on a consistent basis, of \$287.4 million (approximately \$3.09 per common share).

GLJ also recognized the existence of four additional pods on Connacher's extensive acreage in the Great Divide region and the likelihood that additional pods will be discovered with additional drilling. Outside of Pod One, no economic value was assigned to these "best estimate" or "low certainty" resources at this time as they have insufficient drilling density, seismic mapping or project definition to be categorized as reserves. In total, GLJ recognized 538 million barrels of probable and possible reserves and low certainty resources on Connacher's lands, with initial and remaining recoverable probable and possible reserves and low certainty resources of 311.2 million barrels.

Shareholders are cautioned that the estimates of reserves and future net revenue for individual properties, such as Great Divide, may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Following submission of its Pod One development application to Alberta's Energy and Utilities Board and Alberta Environment, Connacher will focus on its financing alternatives over the next several months, while continuing the process of detailed engineering design, procurement and preparation for expanded field activity and plant construction. The regulatory review is expected to take approximately six months. Additionally, plans will be formulated for an extensive core hole program of up to 50 wells on already-identified pods, including several additional wells on Pod One, which could further expand its reserve base.

In reviewing financing alternatives, Connacher's goal for shareholders is maximum value retention at minimum dilution. A review of downstream integration alternatives will also be factored into this evaluation, with a view to a reduction of the price differential risks associated with heavy oil production. Other alternatives including joint venturing and tax-driven partnerships are being evaluated. The significant escalation in investor and industry interest in the oil sands should work in the company's favor as its strategy is crystallized into action.

Subsequent to the reporting period, Connacher also acquired a further six sections (3,840 acres) of oil sands leases and five sections (3,200 acres) of P&NG rights in the Great Divide region for approximately \$218,000. These lands are contiguous with or associated with the Company's existing landholdings in the region.

## RESERVES

In addition to the GLJ evaluation of reserves and resources at Great Divide, Connacher has also received updated estimates of its conventional Canadian reserves and the Argentinean properties of Petrolifera, as prepared by DeGolyer and MacNaughton Canada Limited ("D&M"), independent Petroleum Consultants of Calgary, Alberta. The effective date of D&M's report is June 30, 2005 and September 1, 2005 for the GLJ report. All reports were prepared in accordance with COGEH and NI 51-101, with each consultant's current and posted price deck applied.

### Remaining Reserves and Future Cash Flow Forecast Price Case at June 30 and September 1, 2005 Company Share

Reserve Category	Remaining Reserves						Future Net Revenue <sup>(8,9,10,11,12)</sup>	
	Crude Oil		Natural Gas		NGLs		Undiscounted	Discounted
	Gross <sup>(1)</sup>	Net <sup>(1)</sup>	Gross <sup>(1)</sup>	Net <sup>(1)</sup>	Gross <sup>(1)</sup>	Net <sup>(1)</sup>		at 10%
	stb	stb	mmcf	mmcf	bbl	bbl	\$000	\$000
Proved Developed <sup>(2)</sup>								
Producing <sup>(5)</sup>	1,514,054	1,195,582	1,190	1,032	2,307	1,618	26,831	20,589
Non-producing <sup>(6)</sup>	1,477	929	160	143	-	-	853	715
Total Proved Developed	1,515,531	1,196,511	1,350	1,175	2,307	1,618	27,684	21,304
Proved Undeveloped <sup>(7)</sup>	450,133	362,698	295	254	-	-	7,047	4,782
TOTAL PROVED ("1P")	1,965,664	1,559,209	1,645	1,429	2,307	1,618	34,731	26,086
Probable <sup>(3)</sup>	70,992,716	62,116,257	1,903	1,653	888	617	852,327	240,513
TOTAL Proved & Probable ("2P")	72,958,380	63,675,466	3,548	3,082	3,195	2,235	887,058	266,599
Possible <sup>(4)</sup>	40,686,571	34,967,572	4,571	3,690	119	103	722,017	78,627
TOTAL Proved & Probable & Possible ("3P")	113,644,951	98,643,038	8,119	7,042	3,314	2,338	1,609,075	345,226

(1) "Gross reserves are the Company's working interest (operating or non-operating) share before deducting royalties and without including any royalty interests of the Company." "Net Reserves" are the Company's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company'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 percent likely that the actual remaining quantities recovered will be greater or less than the sum of 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 exceed the estimated proved plus probable reserves.

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

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

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

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

(8) The values do not necessarily represent the fair market value.

(9) Including ARTC.

(10) Before income taxes and indirect costs and after capital costs and future abandonment costs net of salvage value.

(11) Includes 100 percent of Petrolifera's Argentinean reserves. Connacher owned 40 percent of Petrolifera at June 30, 2005

(12) May not add due to rounding.

Additionally, GLJ also assigned 202.6 million low certainty recoverable resources to four pods and two prospective pods on Connacher's Great Divide oil sands properties, with no economic value calculated for these resources until they can be upgraded to project and reserve status.

Of the Company's total 73.6 million boes of gross proved and probable recoverable reserves, 72.2 million boes are located in Canada with the balance in Argentina. Of total Canadian probable reserves, 69.6 million barrels or 96 percent are in Pod One at Great Divide with the balance primarily at Battrum and Tompkins, Saskatchewan.

Of the Company's total 41.4 million boes of gross possible reserves, 39.8 million boes are located in Canada with the balance in Argentina. Of total Canadian possible reserves, 38.7 million barrels or 97 percent are in Pod One located at Great Divide, Alberta with the balance at conventional properties in Saskatchewan.

Sixty percent of the equity of Petrolifera is owned by shareholders other than Connacher, and accordingly while the accounts of Petrolifera are consolidated with those of Connacher as at June 30, 2005, 788,000 boes of proved and probable reserves and 997,000 boe's of possible reserves owned by Petrolifera are not beneficially owned by Connacher due to the ownership structure of Petrolifera.

The 10% present value of the Company's future net revenue from proved and probable reserves has increased from \$33.2 million at year-end 2004 to \$266.6 million (\$2.90 per basic common share) as at June 30, 2005, an increase of 703 percent. Connacher's 2P recoverable reserve volumes are 1,814 percent above year end 2004; 3P gross reserve volumes have increased 102 percent.

## PETROLIFERA PETROLEUM LIMITED

### Argentina

As previously reported, in early 2005 Petrolifera completed a 150 square kilometer 3D seismic program over a significant portion of the Puesto Morales/Rinconada concession in the Neuquen Basin, Argentina. Interpretation of the seismic has resulted in nine drillable locations, with attractive reserve potential. A shortage of available rigs has precluded drilling these prospects, but Petrolifera is in the queue for a drilling rig and a completion rig to drill up to five successive wells, commencing October 1, 2005. Drilling will be initiated sooner if a rig becomes available. The prospects to be drilled are relatively shallow 1,500 – 1,700 metre tests to evaluate several horizons for both oil and natural gas, with the Sierras Blancas and Quintico the primary objectives. If success is achieved, numerous follow-up development locations are anticipated.

Effective June 1, 2005, the price received by Petrolifera for natural gas being sold in Argentina was renegotiated to a level of \$1.13 per mcf, an increase of over 50 percent. The price is subject to further review and adjustment every six months.

### Peru

Subsequent to the reporting period, the formal signing ceremony for License 106 in the Maranon Basin took place in Lima, Peru. This two million acre block is well-situated, surrounding the Corrientes Field, a 200 million barrel field and the largest in the Basin. Furthermore, the block is surrounded by other smaller fields and is bisected by an underutilized pipeline, such that any new discovery could access markets quickly.

The signing ceremony for Block 107 in the Ucayali Basin is tentatively scheduled for August 23, 2005. This is also a high potential block covering over three million acres northwest of and on trend with the giant Camisea natural gas complex.

Connacher and Petrolifera are enthused about the potential of these two large, significant blocks. Serious exploration work will be initiated once baseline environmental studies are completed. Peru is emerging as a dynamic and resurgent country for the oil and gas business and further opportunities are being examined.

## CORPORATE

Mr. Gary Freeman resigned as a director of Connacher for personal reasons, including a decision to relocate in Victoria, B.C. The Company thanks Mr. Freeman for his contribution since he became a director. A replacement director will be appointed in due course.

Respectfully submitted on behalf of the Board of Directors

Signed,  
"R.A Gusella"

**Richard A. Gusella**  
President and Chief Executive Officer

August 10, 2005

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

The following is dated as of August 10, 2005 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 six months ended June 30, 2005 and 2004 as contained in this interim report and the annual MD&A and audited consolidated financial statements for the years ended December 31, 2004 and December 31, 2003. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and are presented in Canadian dollars. Additional information relating to the company, including the company's 2004 Annual Report and Annual Information Form ("AIF"), is on SEDAR at [www.sedar.com](http://www.sedar.com). 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 forward-looking information involves a number of risks and uncertainties and actual results may vary materially from those anticipated by the company. These risks and uncertainties include, but are not limited to, changes in market conditions, law or governing policy, operating conditions and costs, operating performance, demand for oil and gas, price and exchange rate fluctuation, currency controls, commercial negotiations and technical and economic factors. 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 oil (6:1). Boes may be misleading particularly if used in isolation. 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.

### FINANCIAL AND OPERATING REVIEW

#### PRODUCTION, PRICING AND REVENUE

	Three Months Ended June 30			Six Months Ended June 30		
	2005	2004	% change	2005	2004	% change
Daily production / sales volumes						
<b>Oil – bbl/d</b>						
Canada	616	955	(35)	580	883	(34)
Argentina	86	49	76	86	49	76
Total	702	1,004	(30)	666	932	(29)
<b>Natural Gas –mcf/d</b>						
Canada	35	1,383	(98)	76	1,562	(95)
Argentina	1,381	477	190	1,296	502	158
Total	1,416	1,860	(24)	1,372	2,064	(34)
<b>Combined – boe/d <sup>(1)</sup></b>						
Canada	622	1,185	(48)	593	1,143	(48)
Argentina	316	129	144	301	133	126
Total	938	1,314	(29)	894	1,276	(30)
<b>Product pricing (\$)</b>						
Oil – per bbl						
Canada	40.70	28.74	42	35.00	29.18	20
Argentina	44.99	43.41	4	42.47	42.80	(1)
Weighted average	41.23	29.46	40	35.96	29.90	20
Natural gas – per mcf						
Canada	6.06	6.57	(8)	5.87	6.08	(3)
Argentina	0.86	0.86	-	0.80	0.53	51
Weighted average	0.99	5.11	(81)	1.08	4.73	(77)
<b>Boe – per boe</b>						
Canada	40.66	30.82	32	35.01	30.84	14
Argentina	16.01	19.83	(19)	15.49	17.82	(13)
Weighted average	32.35	29.74	9	28.42	29.49	(4)
<b>Petroleum and natural gas sales (\$000's)</b>						
Canada	2,301	3,323	(31)	3,755	6,416	(41)
Argentina	460	233	97	846	430	97
Total	2,761	3,556	(22)	4,601	6,846	(33)
<b>Other income (\$000's)</b>						
Canada	35	-		53	-	
Argentina	-	-		-	-	
Total	35	-		53	-	

(1) All references to barrels of oil equivalent are calculated on the basis of 6 mcf: 1 bbl.

Results for the second quarter of 2005 were significantly affected by the disposition of Canadian producing oil and gas properties in July 2004. Production from these properties represented approximately 500 boe/d or 40 percent of the company's second quarter 2004 daily production. The decline in Canada was offset by an increase in Argentinean production, primarily as a result of purchasing the operator's 50 percent working interest near year end 2004. As a consequence of the resultant 29 percent decrease in sales volume in the second quarter and an increase in overall product pricing of nine percent from the second quarter of the prior year, total revenue in the second quarter of 2005 decreased by 22 percent to \$2.8 million compared to \$3.6 million reported in the second quarter of 2004. Canadian revenues for the second quarter were \$2.3 million, down 30 percent from \$3.3 million in the same 2004 period (due to the aforementioned property sales), while Argentinean revenues were up 97 percent to \$460,000 from \$233,000 in 2004.

The price realized for Canadian oil sales was \$40.70 per barrel, up 42 percent in the second quarter of 2005 compared with 2004, and was up 20 percent to \$35.00 per bbl for 2005 year-to-date compared to \$29.18 realized in the first six months of 2004. This increase was a result of higher world oil prices (WTI rose 39 percent in the second quarter 2005 compared to the second quarter 2004 and increased by 40 percent in the first half of 2005 compared to the first half of 2004), and the expiry on March 31, 2005 of an oil sales contract for a portion of crude oil sales at a price lower than world market prices. The Company now sells its crude oil at market prices with a US \$0.50 premium per barrel.

Results for the first half of 2005 reflect similar changes for the same reasons. Total revenues of \$4.7 million were down 33 percent from the prior year, reflecting a reduction of 30 percent in sales volumes and a four percent reduction in product pricing. Canadian revenues of \$3.8 million were down 40 percent as a result of a sales volumes decline of 48 percent, offset by an increase in product pricing of 14 percent. For Argentina, year-to-date revenues of \$846,000 represents a 97 percent increase from 2004, as a result of sales volumes increasing by 126 percent, offset by a thirteen percent decline in pricing.

As a result of the 2004 property sales, natural gas sales volumes in Canada were nominal. Consequently, the low regulated natural gas price received in Argentina has had a significant effect on reducing the overall natural gas selling price from \$4.73 per mcf to \$1.08 this year. Recently natural gas pricing in Argentina has improved to \$1.13 per mcf (from \$0.74 per mcf), and is expected to continue to rise in the near term. However, these prices are expected to continue to be significantly lower than unregulated North American natural gas market prices.

## ROYALTIES

	For the Six Months Ended June 30			
	2005		2004	
	Total	Per boe	Total	Per boe
Canada	\$958,875	\$8.94	\$1,246,947	\$5.99
percentage of total oil and gas revenue	26%		19%	
Argentina	\$98,719	\$1.81	\$70,178	\$2.91
percentage of total oil and gas revenue	12%		16%	
<b>Total</b>	<b>\$1,057,594</b>	<b>\$6.53</b>	<b>\$1,317,125</b>	<b>\$5.68</b>
percentage of total oil and gas revenue	23%		19%	

Royalties represent charges against production or revenue by governments and landowners. Royalties in the second quarter of 2005 were \$689,000 (\$8.07 per boe, or 26 percent of oil and gas revenue) compared to \$712,000 in the second quarter of 2004 (\$5.95 per boe, or 22 percent of oil and gas revenue). From period to period, royalties can change slightly based on changes to the weighting in the product mix which is subject to different royalty rates, and rates usually escalate with increased product prices. The change from 2004 to 2005 reflects this.

For the year-to-date, royalties were \$1.1 million (23 percent of revenue or \$6.53 per boe) compared to \$1.3 million (19 percent of revenue or \$5.68 per boe) for the first six months of 2004. This twenty percent overall reduction in royalties reflects the overall 30 percent reduction in sales volumes offset by the consequence to crude oil royalties of a twenty percent increase in Canadian oil prices.

## OPERATING EXPENSES AND OPERATING NETBACKS

### Company Operating Netbacks - combined Canada and Argentina <sup>(1)</sup> For the six months ended June 30

	2005		2004		% Change	
	Total	Per boe	Total	Per boe	Total	Per boe
Average daily production (boe/d)	894		1,276		(30)	
Petroleum and natural gas revenue	\$4,600,486	\$28.42	\$6,846,040	\$29.49	(33)	(4)
Other income	52,992	0.33	-	-	-	-
Total revenue	4,653,478	28.75	6,846,040	29.49	(32)	(3)
Royalties	(1,057,594)	(6.53)	(1,317,125)	(5.68)	(20)	15
Net revenue	3,595,884	22.22	5,528,915	23.81	(35)	(7)
Operating costs	(1,159,362)	(7.16)	(2,397,686)	(10.32)	(52)	(31)
Transportation costs	(9,525)	(0.06)	(84,593)	(0.37)	(89)	(84)
<b>Operating netback</b>	<b>\$2,426,997</b>	<b>\$15.00</b>	<b>\$3,046,636</b>	<b>\$13.12</b>	<b>(20)</b>	<b>14</b>

(1) Calculated by dividing related revenue and costs by total boe produced, resulting in an overall combined company netback.

Operating costs decreased by 52 percent in the second quarter of 2005 to \$629,000 compared to \$1.3 million in the comparative 2004 quarter. This reflects reduced sales volumes, together with better operating efficiencies with current production. Second quarter 2005 unit costs of \$7.42 per boe were 34 percent lower than \$11.26 per boe in the same 2004 period. Following the sale of the Cabri, Saskatchewan property and the higher-cost heavy oil production at Islay and Lloydminster, Alberta, current quarter Canadian operating costs have declined to \$8.44 per boe (\$11.88 per boe in the second quarter of 2004). Argentinean operating costs were down slightly from last year, averaging \$5.41 per boe in the second quarter of 2005 compared to \$5.58 per boe in the second quarter of 2004.

The benefit of having sold the higher-operating cost properties in 2004 is also reflected in lower year-to-date operating costs. Overall operating costs were down 52 percent to \$1.2 million from \$2.4 million and by 31 percent on a boe basis to \$7.16 from \$10.32 in the first half of 2004.

Transportation costs were lower as a result of having sold the higher-cost heavy oil properties in 2004 resulting in lower volumes and less trucking costs.

### 2005 Operating Netbacks by Country and Product

For the six months ended June 30, 2005

Per unit netbacks are calculated by dividing netbacks by sales volumes.

Operating netbacks by product type and by country are indicated below.

	Canada				Argentina			
	Crude oil		Natural gas		Crude oil		Natural gas	
	Total	Per bbl	Total	Per mcf	Total	Per bbl	Total	Per mcf
<b>Average daily production</b>	580 bbl/d		76 mcf/d		86 bbl/d		1,296 mcf/d	
Total revenue	\$3,673,404	\$35.00	\$81,317	\$5.87	\$658,636	\$42.47	\$187,129	\$0.80
Royalties	(954,236)	(9.09)	(4,639)	(0.34)	(77,319)	(4.99)	(21,400)	(0.09)
Operating and transportation costs	(865,502)	(8.25)	(40,069)	(2.91)	(206,236)	(13.30)	(57,080)	(0.24)
<b>Operating netback</b>	<b>\$1,853,666</b>	<b>\$17.66</b>	<b>\$36,609</b>	<b>\$2.62</b>	<b>\$375,081</b>	<b>\$24.18</b>	<b>\$108,649</b>	<b>\$0.47</b>

Consolidated operating netbacks for the second quarter of 2005 increased 38 percent to \$17.28 per boe compared to the second quarter of 2004. Canadian netbacks in the second quarter of 2005 were \$21.69 per boe up 69 percent from the same 2004 period. These increases were primarily due to the increase in oil prices and lower operating costs. For the second quarter of 2005, Argentinean netbacks were down seven percent to \$9.21 per boe compared to \$9.89 for the same 2004 period, as a result of operating costs per boe being slightly higher in 2005.

For the year-to-date, consolidated operating netbacks were \$15.00 per boe, a 14 percent increase from the \$13.12 reported in the first half of 2004.

Canadian netbacks for the 2005 year-to-date were \$17.62 per boe, compared to \$13.53 per boe in the first six months of 2004, while Argentinean netbacks averaged \$8.86 per boe in the first six months of 2005, compared to \$9.58 per boe in the first six months of 2004. The lower Argentinean netbacks primarily reflect low natural gas prices compared to North America.

Netbacks do not have a standardized meaning prescribed by GAAP and therefore may not be comparable to similar measures used by other companies. Nevertheless, Connacher's management uses netback as a performance measurement.

### GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative (G&A) expenses decreased by \$106,000 to \$582,000 in the second quarter of 2005, due to a reduction in public company and staffing costs. These reductions exceeded the added costs incurred in respect of establishing additional international operations for Petrolifera. For the year-to-date, however, G&A costs increased by \$155,000, primarily to establish Petrolifera's operations.

A non-cash stock-based compensation expense of \$331,000 (2004 - \$41,000) was also incurred in the first six months of 2005 reflecting the fair value of all stock options granted and vested in the period. In 2005 year-to-date, G&A of \$73,000 was capitalized (2004 - \$nil).

A reduction in unit costs is expected as volumes increase, especially when Great Divide production commences.

### INTEREST AND FOREIGN EXCHANGE

In late 2004 the company paid off its bank debt and has had limited indebtedness in 2005. In future Connacher will utilize banking facilities as appropriate to leverage shareholders' capital while growing the company. No debt was used in the Argentinean operations.

When translating foreign denominated financial statements and operating results, the impact of fluctuations on the Argentinean peso relative to the Canadian dollar resulted in a foreign exchange gain of \$22,000 in the second quarter and \$42,000 in the 2005 year-to-date (2004 - \$2,000 for each comparative period). The company's main exposure to foreign currency risk relates to the pricing of crude oil sales, which are denominated in US dollars.

### DEPLETION, DEPRECIATION AND ACCRETION

Depletion, depreciation and accretion (DD&A) expense is calculated using the unit-of-production method based on total estimated proved reserves. DD&A in the second quarter of 2005 was \$1.2 million, a 43 percent decrease from last year. This decrease is primarily the result of substantially lower production and sales volumes. For the year-to-date, DD&A was \$2.4 million, a 42 percent decrease from the first six months of 2004, or \$14.74 per boe compared to \$17.69 per boe, a 17 percent reduction from 2004, and an improved production-to-proved reserve ratio.

Capital costs of \$12.6 million (2004 - \$ 5.9 million) related to major development projects in a pre-production state in Argentina, at Tompkins,

Saskatchewan and at the Great Divide oil sands project have been excluded from depletable costs. No proved reserves have been assigned to these projects. Additionally, undeveloped land acquisition costs of \$2.3 million (2004 – \$3.6 million) were excluded from the depletion calculation, while future development costs of \$3.7 million for proved undeveloped reserves were included in the depletion calculation.

Included in DD&A is a charge of \$72,000 (2004 - \$119,000) to accrete the company's estimated asset retirement obligation. These charges will continue to be necessary in future to accrete the currently booked discounted liability of \$3.0 million to the estimated total undiscounted liability of \$5.7 million over the estimated remaining economic life of the company's oil and gas properties.

#### DILUTION GAIN

In March 2005 Petrolifera completed a \$7 million private placement financing consisting of common shares and common share purchase warrants. As Connacher did not participate in the financing, its interest in Petrolifera was reduced to 40 percent from 61 percent. Petrolifera repaid \$2 million of its indebtedness to Connacher from proceeds of the financing, reducing the amount owing to Connacher pursuant to an outstanding promissory note to \$750,000. The 21 percent reduction in Connacher's interest in Petrolifera resulted in a gain to the company of \$3 million in the first quarter of 2005. If market conditions permit, a public financing is contemplated by Petrolifera in 2005.

#### INCOME APPLICABLE TO NON-CONTROLLING INTERESTS

The non-controlling interests credit of \$88,000 reported in the second quarter of 2005 (2004 – nil) and \$123,000 for the year-to-date (2004 – nil) represents the non-controlling shareholders' equity share of the loss of the consolidated entity, Petrolifera.

#### TAXES

The current income tax recovery of \$55,000 for the second quarter and \$42,000 for the year-to-date relates to income taxes recoverable in Argentina for which a provision was made in 2004. There are no Canadian cash taxes payable, as the company has substantial Canadian tax pools to shelter its income.

A future tax provision of \$167,000 was recorded in the first half of 2005. In the comparative 2004 period the company reported recoverable future taxes of \$730,000.

At June 30, 2005 the company had approximately \$44 million of deductible tax pools and approximately \$4 million of operating loss carry-forwards in Canada to shelter future taxable income. These tax pools will be supplemented with ongoing capital expenditures.

#### 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 2005 or 2004.

#### NET EARNINGS AND SHARES OUTSTANDING

##### For the six months ended June 30

	2005		2004		% change	
	Total	Per boe	Total	Per boe	Total	Per boe
Operating netback	\$2,426,997	\$15.00	\$3,046,636	\$13.12	(20)	14
General & administrative	(1,251,456)	(7.73)	(1,096,683)	(4.72)	14	64
Stock-based compensation	(331,011)	(2.04)	(41,000)	(0.18)	707	1,033
Interest	(76,006)	(0.47)	(490,020)	(2.11)	(84)	(77)
Foreign exchange gain (loss)	41,860	0.25	1,557	-	2,589	-
Depletion, depreciation and accretion	(2,386,049)	(14.74)	(4,107,591)	(17.69)	(42)	(17)
Dilution gain	3,020,329	18.66	-	-	-	-
Non-controlling interests	123,220	0.76	-	-	-	-
Income tax recovery (provision)	(124,579)	(0.77)	730,000	3.14	-	-
Net earnings (loss)	\$1,443,305	\$8.92	\$(1,957,101)	\$(8.44)	-	-

In the second quarter of 2005 the company reported a net loss of \$230,000 (\$nil per basic and diluted share outstanding). This compares to a net loss of \$1.3 million or \$0.03 loss per basic and diluted share outstanding for the same 2004 period.

For the year-to-date the company reported net earnings of \$1.4 million (\$0.02 per basic and diluted share outstanding) compared to a loss of \$2 million (\$0.04 loss per basic and diluted share outstanding) for the first six months of 2004.

In the 2005 year-to-date, the weighted average number of shares outstanding was 92,036,801 (2004 – 46,553,292) and the weighted average number of diluted shares outstanding, as calculated by the treasury stock method, was 94,717,025 (2004 – 49,149,819). The substantial increase in shares outstanding period over period reflects the 2004 issuance from treasury of 41,706,663 common shares for gross cash proceeds of \$21.3 million.

As at August 10, 2005, the company had the following securities issued and outstanding:

- 93,302,538 common shares;
- 2,065,730 share purchase warrants; and
- 6,962,700 share purchase options.

Details of the exercise rights and terms of the warrants and options are noted in the consolidated financial statements, included in this quarterly report.

## LIQUIDITY AND CAPITAL RESOURCES

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 from operations before working capital changes includes all cash flow from operating activities and is calculated before changes in non-cash working capital. The most comparable measure calculated in accordance with GAAP would be net earnings. Cash flow from operations before working capital changes is reconciled with net earnings on the Consolidated Statement of Cash Flows and below. Cash flow per share is calculated by dividing cash flow from operations before working capital changes by the weighted average shares outstanding; cash flow per boe is calculated by dividing cash flow from operations before working capital changes by the quantum of crude oil and natural gas (expressed in boe's) 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.

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

	Three months ended June 30, 2005	Six months ended June 30, 2005
<b>Net earnings (loss)</b>	(229,742)	1,443,305
<b>Add (deduct):</b>		
Stock-based compensation	113,961	331,011
Depletion, depreciation and accretion	1,192,715	2,386,049
Future income tax provision (recovery)	(89,420)	166,828
Foreign exchange gain	(22,218)	(41,860)
Loss applicable to non controlling interests	(88,110)	(123,220)
Dilution gain	-	(3,020,329)
Cash flow from operations before working capital changes	877,186	1,141,784

Cash flow in the second quarter of 2005 was \$877,000 (\$0.01 per basic and diluted share) compared to \$516,000 (\$0.01 per basic and diluted share) in the same 2004 period.

For the year-to-date cash flow was \$1.1 million (\$0.01 per basic and diluted share) compared to \$1.5 million (\$0.03 per basic and diluted share) in the first six months of 2004.

Cash flow per boe was \$10.28 in the second quarter of 2005 compared to \$4.32 in the second quarter of 2004. This represents 32 percent of the average company selling price compared to 15 percent in 2004.

Cash flow per boe for the first six months of 2005 was \$7.06 per boe compared to \$6.29 per boe for the same period in 2004.

In the second quarter of 2005 the company drilled a total of 4.75 net wells at Battrum, Saskatchewan. Total capital expenditures in the second quarter were \$5.6 million.

For the first six months of 2005, capital expenditures totaled \$11.7 million. A breakdown of these expenditures for the sixth month period is as follows:

- \$7 million, primarily in Canada for drilling 19 oil sands delineation core holes, 4.75 net conventional oil wells and for workovers of conventional wells at Battrum, Saskatchewan;
- \$3 million for seismic and research studies in Canada and Argentina;
- \$1 million for property acquisitions in Canada; and
- \$700,000 for other expenditures.

### Great Divide Oil Sands Project, Northern Alberta

The company holds a 100 percent working interest in 64,640 acres of oil sands leases in northern Alberta. To date, the focus has been on a four section tract ("Pod One") on which approximately \$9 million has been invested to acquire the oil sands leases, to delineate the oil bearing reservoir in the first Pod, and to prepare an application for regulatory approval to develop a 10,000 bbl/d steam assisted gravity drainage ("SAGD") project in 2006 for Pod One. Capital development costs for Pod One are being determined and are expected to reach up to \$200 million. Subject to further refinement, approximately two-thirds of these forecast expenditures are anticipated to be for surface facilities with the balance of the costs to drill the initial horizontal well pairs. Management and the board of directors are assessing the best means to finance this project, including maintaining a 100 percent working interest and raising new equity and debt or exchanging a portion of the company's interests in a joint venture arrangement for third party funding.

### Tompkins Natural Gas Project, Southwest Saskatchewan

In late 2003 and in early 2004, the company drilled and cased nine natural gas wells and one oil well. Costs incurred to date have been on budget. The oil well has been producing throughout 2004 and 2005 and has paid out. The natural gas wells require further evaluation and additional wells will likely be required to establish a sufficient reserve base for commercial exploitation. The company was financially constrained for most of 2004 and deferred this activity, but now has increased financial capacity to complete the project, pending availability of services, surface access to the leases due to environmental sensitivity and prioritization of investment alternatives.

## **Argentina**

In 2005 expenditures of \$1.2 million were incurred for new 3D seismic to validate a new development drilling program on the Puesto Morales/Rinconada concession in the Neuquen Basin, Argentina. A development drilling program will commence as soon as a drilling rig can be secured. This activity will be financed from the proceeds of the private placement financing completed by Petrolifera in March 2005.

## **FINANCING ACTIVITIES**

Other than the financing required for the capital costs of the Great Divide Oil Sands Project, management believes that available cash and banking lines of credit together with operating cash flow will provide sufficient funding for working capital purposes and for the company's planned capital program on conventional properties in the short term. In the longer term, it may be necessary to access additional capital in the equity markets. Except for a commitment to incur \$65,000 of capital expenditures on behalf of joint venturers in the Tompkins area, the company's capital program is entirely discretionary and may be expanded or curtailed based on drilling results. This is reinforced by the fact that Connacher operates most of its wells and holds an average 92 percent working interest.

The equity financing completed in late 2004 included the issuance of flow-through shares for proceeds of \$7,024,000. Resource expenditures of \$7,024,000 were renounced to investors effective December 2004. The company has until the end of 2005 to incur the costs. At August 10, 2005, the company had fulfilled approximately \$5.7 million of this obligation. The remaining \$1.3 million obligation is expected to be satisfied upon the completion of management's planned capital program and is expected to be funded from currently available cash balances and operating cash flow.

## **OUTLOOK**

The company's business plan for 2005 is expected to facilitate substantial growth. To accomplish this growth the company expects a measured but active capital program of oil and gas property acquisition and development drilling in Canada and in Argentina. Emphasis is expected to be placed on delineating and developing the Great Divide oil sands property in Alberta while the conventional production base provides funds to cover the company's overhead requirements and fund a portion of capital expenditures.

Forecast operating cash flow, available cash, possible new bank borrowings and additional equity as required will finance Connacher's expected 2005 capital spending program. Joint ventures may also be utilized.

All estimates and statements which may have been issued with respect to 2005 expectations are forward-looking statements. This involves inherent risks and uncertainties where actual results will differ and such differences could be material. There can be no assurance Connacher will achieve the drilling results and levels of production it might assume in developing its internal 2005 capital budget and financial plan. In addition, oil and gas prices are subject to fluctuation and there can be no assurance that the prices assumed for the company's internal 2005 plan, or any variation thereof, will be attained. Reference is made to the company's AIF for a description of the risks and uncertainties affecting the company and its business.

**QUARTERLY RESULTS**

Three Months Ended	2003			2004			2005		
	Jun 30	Sept 30	Dec 31	Mar 31	Jun 30	Sept 30	Dec 31	Mar 31	Jun 30
<b>Financial Highlights</b> (\$000 except per share amounts) - Unaudited									
Total revenue	2,474	2,491	2,853	3,290	3,556	2,358	1,975	1,857	2,796
Cash flow from operations before working capital changes <sup>(1)</sup>	821	745	1,008	944	516	478	471	265	877
Basic, per share <sup>(1)</sup>	0.02	0.02	0.03	0.02	0.01	0.01	0.01	-	0.01
Diluted, per share <sup>(1)</sup>	0.03	0.02	0.02	0.02	0.01	0.01	0.01	-	0.01
Net earnings (loss)	44	2,815	1,030	(689)	(1,268)	(869)	(150)	1,673	(230)
Basic, per share	-	0.08	0.04	(0.01)	(0.03)	(0.02)	-	0.02	-
Diluted, per share	-	0.07	0.04	(0.01)	(0.03)	(0.02)	-	0.02	-
Capital expenditures	4,272	5,715	15,015	10,391	2,603	681	3,954	6,047	5,649
Proceeds on disposal of PNG properties	-	-	-	-	89	17,564	(49)	-	-
Bank debt	12,500	13,800	12,100	20,600	23,655	7,563	-	-	250
Working capital surplus (deficiency)	(179)	(2,695)	(8,994)	(9,850)	(8,357)	(6,644)	3,549	5,588	854
Cash on hand (net debt)	(12,679)	(16,495)	(21,094)	(30,450)	(32,012)	(14,207)	3,914	8,286	2,629
Shareholders' equity	9,718	13,613	24,182	21,655	20,933	20,217	40,502	41,206	41,217
<b>Operating Highlights</b>									
Production / sales volumes									
Natural gas - mcf/d	1,033	1,012	1,496	2,268	1,860	1,068	1,290	1,328	1,416
Crude oil - bbl/d	752	839	978	859	1,004	636	646	629	702
Equivalent - boe/d <sup>(2)</sup>	924	1,008	1,228	1,237	1,314	814	861	850	938
Pricing									
Crude oil - \$/bbl	33.10	29.40	26.96	30.41	29.46	36.58	30.68	30.02	41.23
Natural gas - \$/mcf	2.18	2.35	3.02	4.42	5.11	2.21	1.29	1.18	0.99
Selected Highlights - \$/boe <sup>(2)</sup>									
Weighted average sales price	29.37	26.84	25.17	29.22	29.74	31.48	24.93	24.04	32.35
Other income	0.04	0.03	0.10	-	-	0.33	0.15	0.24	0.41
Royalties	5.20	5.08	4.23	5.37	5.95	6.06	4.64	4.82	8.06
Operating and transportation costs	7.46	7.89	10.29	10.09	11.26	8.70	7.98	7.01	7.42
Operating netback <sup>(3)</sup>	16.75	13.90	10.75	13.76	12.53	17.05	12.47	12.45	17.28
<b>Common Share Information</b>									
Shares outstanding at end of period (000's)	34,082	36,512	45,903	46,153	47,368	47,668	89,627	92,753	93,013
Weighted average shares outstanding for the period									
Basic (000's)	29,421	35,820	39,022	46,067	47,042	47,400	50,908	91,189	92,875
Diluted (000's)	31,945	38,817	42,138	50,119	48,496	47,504	53,329	94,197	95,555
Volume traded during quarter (000's)	8,342	10,027	15,045	20,706	30,108	8,880	25,256	40,486	16,821
Common share price (\$)									
High	0.76	0.87	1.60	1.75	1.08	0.44	0.80	1.22	1.05
Low	0.40	0.65	0.74	0.73	0.30	0.28	0.29	0.49	0.68
Close (end of period)	0.71	0.75	1.60	0.78	0.40	0.32	0.55	0.93	0.82

- (1) Cash flow from operations before working capital changes and cash flow per share do not have standardized meanings prescribed by Canadian generally accepted accounting principles ("GAAP") and therefore may not be comparable to similar measures used by other companies. Cash flow from operations before working capital changes includes all cash flow from operating activities and is calculated before changes in non-cash working capital. The most comparable measure calculated in accordance with GAAP would be net earnings. Cash flow from operations before working capital changes is reconciled with net earnings on the Consolidated Statement of Cash Flows and in the accompanying Management Discussion & Analysis. Management uses these non-GAAP measurements for its own performance measures and to provide its shareholders and investors with a measurement of the company's efficiency and its ability to fund a portion of its future growth expenditures.
- (2) All references to barrels of oil equivalent (boe) are calculated on the basis of 6 mcf : 1 bbl. Boes may be misleading, particularly if used in isolation. This conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
- (3) For detailed netbacks by product type and by country, see "Operating Expenses and Operating Netbacks", in this MD&A.

# Consolidated Balance Sheets

CONNACHER OIL AND GAS LIMITED

	June 30 2005	December 31 2004
	(unaudited)	
	\$	\$
<b>ASSETS</b>		
CURRENT		
Cash and cash equivalents	2,878,857	3,914,181
Accounts receivable	2,181,341	1,773,005
Prepaid expenses	211,918	309,062
	5,272,116	5,996,248
Property and equipment	45,969,774	36,542,595
Future income tax asset	1,190,000	3,678,270
	52,431,890	46,217,113
<b>LIABILITIES</b>		
CURRENT		
Accounts payable	4,168,081	2,446,947
Bank loan (Note 5)	250,000	-
	4,418,081	2,446,947
Asset retirement obligations (Note 4)	2,997,500	2,905,477
Deferred credits	310,668	353,771
Non-controlling interests (Note 2)	3,488,443	8,930
	11,214,692	5,715,125
<b>SHAREHOLDERS' EQUITY</b>		
Share capital and contributed surplus (Note 6)	38,562,724	39,290,819
Retained earnings	2,654,474	1,211,169
	41,217,198	40,501,988
	52,431,890	46,217,113

# Consolidated Statements of Operations and Retained Earnings

CONNACHER OIL AND GAS LIMITED

(unaudited)	Three Months Ended June 30		Six Months Ended June 30	
	2005	2004	2005	2004
	\$	\$	\$	\$
<b>REVENUE</b>				
Petroleum and natural gas sales	2,761,324	3,556,538	4,600,486	6,846,040
Other income	34,865	(436)	52,992	-
	2,796,189	3,556,102	4,653,478	6,846,040
Royalties	(688,780)	(711,878)	(1,057,594)	(1,317,125)
	2,107,409	2,844,224	3,595,884	5,528,915
<b>EXPENSES</b>				
Operating	629,439	1,290,511	1,159,362	2,397,686
Transportation	3,450	55,773	9,525	84,593
General and administrative	581,893	688,415	1,251,456	1,096,683
Stock-based compensation	113,961	-	331,011	41,000
Interest	70,487	293,332	76,006	490,020
Foreign exchange loss (gain)	(22,218)	(1,586)	(41,860)	(1,557)
Depletion, depreciation and accretion	1,192,715	2,085,582	2,386,049	4,107,591
Dilution gain (Note 3)	-	-	(3,020,329)	-
	2,569,727	4,412,027	2,151,220	8,216,016
Earnings (loss) before taxes and non-controlling interests	(462,318)	(1,567,803)	1,444,664	(2,687,101)
				-
Current income tax provision (recovery)	(55,046)	-	(42,249)	
Future income tax provision (recovery)	(89,420)	(300,000)	166,828	(730,000)
	(144,466)	(300,000)	124,579	(730,000)
Earnings (loss) before non-controlling interests	(317,852)	(1,267,803)	1,320,085	(1,957,101)
Loss applicable to non-controlling interests	88,110	-	123,220	-
<b>NET EARNINGS (LOSS)</b>	(229,742)	(1,267,803)	1,443,305	(1,957,101)
<b>RETAINED EARNINGS, BEGINNING OF PERIOD</b>	2,884,216	3,498,282	1,211,169	4,187,580
<b>RETAINED EARNINGS, END OF PERIOD</b>	2,654,474	2,230,479	2,654,474	2,230,479
<b>EARNINGS (LOSS) PER SHARE</b>				
Basic and diluted	-	(0.03)	0.02	(0.04)
<b>WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING</b>				
Basic	92,875,192	47,041,735	92,036,801	46,553,292
Diluted	95,555,417	48,496,047	94,717,025	49,149,819

# Consolidated Statements of Cash Flows

CONNACHER OIL AND GAS LIMITED

(unaudited)	Three Months Ended June 30		Six Months Ended June 30	
	2005	2004	2005	2004
<b>Cash provided by (used in) the following activities:</b>	\$	\$	\$	\$
<b>OPERATING</b>				
Net earnings (loss)	(229,742)	(1,267,803)	1,443,305	(1,957,101)
Items not involving cash:				
Depletion, depreciation and accretion	1,192,715	2,085,582	2,386,049	4,107,591
Stock-based compensation	113,961	-	331,011	41,000
Future income tax provision (recovery)	(89,420)	(300,000)	166,828	(730,000)
Foreign exchange loss (gain)	(22,218)	(1,586)	(41,860)	(1,557)
Dilution gain	-	-	(3,020,329)	-
Loss applicable to non-controlling interests	(88,110)	-	(123,220)	-
Cash flow from operations before working capital changes	877,186	516,193	1,141,784	1,459,933
Changes in non-cash working capital	(3,298,847)	(3,520,039)	(107,691)	(3,291,133)
	(2,421,661)	(3,003,846)	1,034,093	(1,831,200)
<b>FINANCING</b>				
Issue of common shares, net of share issue costs	138,350	546,180	1,631,855	637,440
Issue of shares by Petrolifera, net of share issue costs (Note 3)	(99,993)	-	6,227,717	-
Increase in bank loans	250,000	3,054,535	250,000	11,554,535
	288,357	3,600,715	8,109,572	12,191,975
<b>INVESTING</b>				
Acquisition and development of oil and gas properties	(5,649,404)	(2,602,469)	(11,696,624)	(12,993,677)
Changes in non-cash working capital	2,375,450	2,005,600	1,517,635	2,005,600
	(3,273,954)	(596,869)	(10,178,989)	(10,988,077)
<b>NET DECREASE IN CASH AND CASH EQUIVALENTS</b>	(5,407,258)	-	(1,035,324)	(627,302)
<b>CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD</b>	8,286,115	-	3,914,181	627,302
<b>CASH AND CASH EQUIVALENTS, END OF PERIOD</b>	2,878,857	-	2,878,857	-
<b>SUPPLEMENTARY INFORMATION – CASH PAYMENTS</b>				
Interest	70,487	293,332	76,006	490,020
Income taxes	9,692	1,775	20,730	3,511

# Notes to the Consolidated Financial Statements

## CONNACHER OIL AND GAS LIMITED

Period ended June 30, 2005 and 2004 (unaudited)

### 1. FINANCIAL STATEMENT PRESENTATION AND ACCOUNTING POLICIES

The interim consolidated financial statements include the accounts of Connacher Oil and Gas Limited, its subsidiaries and Petrolifera Petroleum Limited (collectively, "Connacher" or the "company"), and are presented in accordance with Canadian generally accepted accounting principles. The company is in the business of exploring, producing and marketing crude oil and natural gas in Canada and South America.

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, 2004. The disclosures provided below are incremental 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, 2004.

### 2. CONSOLIDATION

Consistent with the audited consolidated financial statements for the year ended December 31, 2004, these unaudited June 30, 2005 financial statements consolidate the accounts of Petrolifera Petroleum Limited ("Petrolifera"). Notwithstanding Connacher's equity interest in Petrolifera was diluted from 61 percent to 40 percent in the first quarter of 2005 (see note 3), Connacher continued to control Petrolifera and therefore continued to consolidate Petrolifera at June 30, 2005 due to the composition of the Petrolifera board of directors and Connacher's management of Petrolifera under the terms of a management agreement.

### 3. DILUTION GAIN

In March 2005 Petrolifera completed a \$7 million private placement financing consisting of seven million common shares, 3.5 million common share purchase warrants and seven million rights. As Connacher did not participate in the financing, its interest in Petrolifera was reduced to 40 percent from 61 percent. Petrolifera repaid \$2 million of its indebtedness to Connacher from proceeds of the financing, reducing to \$750,000 the amount owing to Connacher pursuant to an outstanding promissory note. The 21 percent reduction in Connacher's interest in Petrolifera resulted in a dilution gain of \$3,020,329 in the first quarter of 2005.

### 4. 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 oil and gas properties:

	Six Months Ended June 30, 2005	Year Ended December 31, 2004
Asset retirement obligation, beginning of period	\$ 2,905,477	\$ 4,784,000
Liabilities incurred	-	663,406
Liabilities settled	-	(206,773)
Liabilities disposed	-	(2,466,660)
Change in estimated future cash flows	19,588	(46,496)
Accretion expense	72,435	178,000
Asset retirement obligation, end of period	\$ 2,997,500	\$ 2,905,477

### 5. BANK LOAN

As at June 30, 2005, the Company had available a \$9.0 million Revolving Reducing Demand Loan ("LOC") with scheduled monthly reductions of \$325,000 commencing July 31, 2005. The LOC bears interest at the bank's prime lending rate plus 3/4 percent on borrowed amounts. At June 30, 2005, the Company had drawn \$250,000 on this facility.

Additionally, the Company had a \$3 million Non-Revolver Acquisition/Development Demand Loan Facility ("AD Facility"). At June 30, 2005, the Company had not drawn any amount on this facility. Interest is charged at prime plus one percent on borrowed amounts on the AD Facility.

Amounts drawn on these loans are secured by a \$50,000,000 fixed and floating charge debenture and a general assignment of book debts.

## 6. 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 \$
Share Capital:		
Balance, December 31, 2004	89,626,743	38,755,561
Issued upon exercise of options	300,000	140,150
Issued upon exercise of warrants	3,085,757	1,569,879
Share issue costs		(45,674)
Tax effect of share issue costs		18,000
Tax effect of flow-through expenditures renounced		(2,697,500)
Balance, Share Capital, June 30, 2005	93,012,500	37,740,416
Contributed Surplus:		
Balance, December 31, 2004		535,258
Fair value of share options granted		319,550
Assigned value of options exercised		(32,500)
Balance, Contributed Surplus, June 30, 2005		822,308
Total Share Capital and Contributed Surplus:		
December 31, 2004		39,290,819
June 30, 2005		38,562,724

### (a) Stock Options

A summary of the Company's outstanding stock option grants, as at June 30, 2005 and 2004 and changes during those periods is presented below:

	2005		2004	
	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price
		\$		\$
Outstanding, beginning of period	3,988,600	0.53	2,830,000	0.45
Granted	1,500,000	0.89	1,424,000	0.53
Expired	(70,000)	0.55	(120,000)	(0.74)
Exercised	(300,000)	0.36	(275,000)	(0.25)
Outstanding, end of period	5,118,600	0.64	3,859,000	0.49

All stock options have been granted for a period of five years. The stock options granted in 2005 vest one-third upon grant, one-third one year after grant and one-third two years after grant.

Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life (Years)
\$0.20 - \$0.30	350,000	1.2
\$0.31 - \$0.70	2,568,600	2.4
\$0.71 - \$1.00	1,960,000	3.3
\$1.01 - \$1.52	240,000	3.8
	5,118,600	

In 2005 a compensatory non-cash expense of \$331,011, including \$11,461 for consolidated companies (2004 - \$41,000; nil for consolidated companies) was recorded in general and administrative expenses, reflecting the fair value of stock options granted and vested during the period.

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:

	2005	2004
Risk free interest rate	3.0%	3.0%
Expected option life (years)	3	3
Expected volatility	53%	53%

The weighted average fair value at the date of grant of all options granted in the first six months of 2005 was \$0.28 per option (2004 - \$0.21).

**(b) Share purchase warrants**

A summary of the Company's outstanding share purchase warrants, as at June 30, 2005 and changes during the period is presented below:

	2005
Outstanding, beginning of period	5,300,525
Exercised	(3,085,757)
Expired	(15,000)
Outstanding, end of period	2,199,768

As at June 30, 2005 the 2,199,768 warrants outstanding were exercisable to purchase common shares from treasury as follows:

- (i) 2,187,368 common shares at \$0.59 per share until their expiry on June 7, 2006;
- (ii) 2,400 common shares at \$0.61 per share until their expiry on June 7, 2006; and
- (iii) 10,000 common shares at \$0.52 per share until their expiry on December 1, 2006;

**(c) Flow-through shares**

In 2005 the Company renounced \$7,023,998 of resource expenditures to flow-through share investors effective December 31, 2004. The tax effect of those expenditures have been recorded in the first quarter of 2005. The Company has until December 31, 2005 to incur those expenditures. As at June 30, 2005, \$5.7 million of those expenditures have been incurred.

## 7. SEGMENTED INFORMATION

The company has operations in Canada and in Argentina, through its ownership interest in Petrolifera. All operating activities are related to exploration, development and production of petroleum and natural gas as follows, including non-controlling interests:

Three Months Ended June 30

	<b>Canada</b>	<b>Argentina</b>	<b>Total</b>
	\$	\$	\$
<b>Three months ended June 30, 2005</b>			
Total revenue	2,336,522	459,667	2,796,189
Net earnings (loss)	(303,604)	73,862	(229,742)
Property and equipment, net	42,097,015	3,872,759	45,969,774
Capital expenditures	5,403,969	245,435	5,649,404
Total assets	47,637,683	4,794,207	52,431,890
<b>Six months ended June 30, 2005</b>			
Total revenue	3,808,870	844,608	4,653,478
Net earnings (loss)	1,324,340	118,965	1,443,305
Property and equipment	42,097,015	3,872,759	45,969,774
Capital expenditures	10,156,183	1,540,441	11,696,624
Total assets	47,637,683	4,794,207	52,431,890
<b>Three months ended June 30, 2004</b>			
Total revenue	3,323,442	232,660	3,556,102
Net earnings (loss)	(1,314,426)	46,623	(1,267,803)
Property and equipment	53,860,982	624,644	54,485,626
Capital expenditures	2,571,469	31,000	2,602,469
Total assets	59,733,046	797,854	60,530,900
<b>Six months ended June 30, 2004</b>			
Total revenue	6,415,790	430,250	6,846,040
Net earnings (loss)	(2,041,346)	84,245	(1,957,101)
Property and equipment	53,860,982	624,644	54,485,626
Capital expenditures	12,927,677	66,000	12,993,677
Total assets	59,733,046	797,854	60,530,900

# Corporate Information

## Officers

**Richard A. Gusella**  
President and Chief Executive Officer

**Peter D. Sametz**  
Executive Vice President and Chief Operating Officer

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

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

**Jennifer K. Kennedy**  
Corporate Secretary  
Partner, Macleod Dixon LLP

**Gary D. Wine**  
President, Petrolifera Petroleum Limited

## Auditors

Deloitte & Touche LLP, Calgary

## Bankers

National Bank of Canada, Calgary

## Solicitors

Macleod Dixon LLP, Calgary

## Reservoir engineers

DeGolyer and MacNaughton Canada Limited, Calgary  
Gilbert Laustsen Jung Associates Ltd, Calgary

## Registrar and transfer agent

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

## Subsidiaries and related companies

COGL Resources Ltd. - (100%)  
Great Divide Oil Company - (100%)  
Petrolifera Petroleum Limited - (40%)

## Stock exchange listing

Toronto Stock Exchange  
Trading symbol - CLL

## Head office

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inquiries@connacheroil.com

## Board of directors

**Richard A. Gusella**  
President and Chief Executive Officer

**Charles W. Berard ( 1, 2, 3)**  
Chairman, Governance Committee

**Colin M. Evans (1, 2, 3)**  
Chairman, Audit Committee

**Stewart D. McGregor (1, 2)**  
Lead Director

(1) Audit Committee  
(2) Governance Committee  
(3) Human Resources Committee

## Abbreviations

ARTC	Alberta Royalty Tax Credit
bbls	barrels
bbl/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
DCF	discounted cash flow
EUB	Energy Utilities Board
GJ	gigajoule
mbbls	thousand barrels
mboe	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbbls	million barrels
mmboe	million barrels of oil equivalent
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGLs	natural gas liquids
PNG	petroleum & natural gas
PV	present value
WI	working interest
WTI	West Texas Intermediate