



PRESS RELEASE

November 11, 2009

CONNACHER CONTINUES STRONG EARNINGS PERFORMANCE DURING THIRD QUARTER 2009; ALGAR CONSTRUCTION REACTIVATED AND PROCEEDING FAVORABLY, ON TIME AND UNDER BUDGET; POSITIVELY POSITIONED FOR 2010; CONFERENCE CALL SCHEDULED FOR 9:00 AM MST NOVEMBER 12, 2009

Calgary, Alberta – Connacher Oil and Gas Limited (CLL-TSX) extended its strong earnings performance during the third quarter of 2009 (“Q3 2009”), buoyed by continued operating progress, foreign exchange gains and stronger crude oil prices. Construction at the company’s second 10,000 bbl/d steam-assisted gravity drainage (“SAGD”) project at Algar advanced significantly over the summer months. Drilling of the planned 17 SAGD well pairs also progressed at a most favorable rate. A plant turnaround at Pod One was completed in September 2009 and the scheduled turnaround at our Great Falls, Montana heavy oil refinery is nearing completion. Remedial work at certain of our conventional properties was also accomplished in a timely and cost-efficient manner.

Having strengthened our balance sheet during the second quarter of this year (“Q2 2009”), we were well financed when we initiated our Algar reactivation. We continue to hold significant cash balances to meet our financial obligations, construct Algar and sundry related facilities and anticipate a timely completion of the project by approximately April 2010. Thereafter, we will require approximately one month to commission the project, followed by approximately 90 days of steaming of the horizontal well pairs, after which we will commence the rampup towards plant capacity, which we anticipate could occur by early 2011. We remain optimistic about our outlook in this regard, as we are about the continuing production buildup at Pod One.

Our refining business has experienced a better year in 2009 than occurred last year. Strong asphalt prices emerged, although poor weather and a slow pace of construction of infrastructure projects during the summer months did not allow full realization of the market’s potential. We are nearing completion of a successful turnaround at our refinery, after 3 ½ years of operation since the last such undertaking.

During the quarter we successfully maintained our significant stake in Petrolifera Petroleum Limited through a modest investment in that company’s financing program. We continue to believe Petrolifera has an excellent inventory of prospects with vast potential.

Our focus during the remainder of this year and into 2010 is to complete Algar, expand our bitumen production base, complete another round of core hole drilling and seismic on our oil sands acreage with a view to expanding our reserve and resource base and maintain our steady conventional production base of crude oil and natural gas in Western Canada. Our increased core hole activity on our oil sands properties will be financed from the proceeds of a recent underwritten bought deal \$30 million flow through share financing, which was well received in the market.

Our Q3 2009 and year-to-date 2009 (“YTD 2009”) results will be the subject of a Conference Call scheduled for 9:00 AM MST on November 12, 2009. To listen to or participate in the live Conference Call please dial either 1-416-644-3415 or 1-877-974-0448. A replay of the event will be available from November 12, 2009 at 11:00 PM MST until November 19, 2009 at 11:59 PM MST. To listen to the replay please dial either 1-416-640-1917 or 1-877-289-8525 and enter the passcode 4178428 followed by the pound sign (#). You can also listen to the conference call online, through the following webcast link:

<http://www.newswire.ca/en/webcast/viewEvent.cgi?eventID=2865500>

Highlights of the Q3 2009 and YTD 2009 results were as follows:

- Construction at the Algar SAGD project reactivated; proceeding most favorably, on schedule and under budget
- Record earnings reported for the quarter and year-to-date 2009 despite lower commodity prices
- Cumulative bitumen production from Pod One has now exceeded four million barrels
- Pod One, refinery and conventional turnarounds in Q3 2009 impacted Q3 2009 production and sales volumes
- \$30 million bought deal flow-through equity financing completed in October 2009
- Stronger crude oil prices buoy renewed interest in oil sands activity

	Three months ended September 30			Nine months ended September 30		
	2009	2008	% Change	2009	2008	% Change
FINANCIAL (\$000 except per share)						
Revenues, net of royalties	151,360	224,558	(33)	313,336	527,230	(41)
Cash flow ⁽¹⁾	10,410	31,130	(67)	15,288	59,505	(74)
Per share, basic ⁽¹⁾	0.03	0.15	(80)	0.05	0.28	(82)
Per share, diluted ⁽¹⁾	0.03	0.14	(79)	0.05	0.27	(81)
Net earnings (loss)	47,767	12,139	294	40,889	16,989	141
Per share, basic (loss)	0.12	0.06	100	0.14	0.08	75
Per share, diluted (loss)	0.11	0.06	83	0.14	0.08	75
Property and equipment additions	100,727	69,175	46	205,218	265,563	(23)
Cash on hand				333,634	236,375	41
Working capital				347,139	200,177	73
Long-term debt				889,113	689,673	29
Shareholders' equity				658,336	496,509	33
Total assets				1,736,126	1,369,533	27
UPSTREAM OPERATING RESULTS						
Daily production / sales volumes						
Bitumen – bbl/d ⁽²⁾	6,551	6,810	(4)	6,336	4,909	29
Crude oil – bbl/d	993	957	4	1,095	976	12
Natural gas – Mcf/d	10,377	13,188	(21)	11,774	12,625	(7)
Barrels of oil equivalent -	9,274	9,966	(7)	9,394	7,990	18

Product pricing ⁽⁴⁾						
Bitumen – \$/bbl ⁽²⁾	45.30	65.34	(31)	36.53	61.98	(41)
Crude oil – \$/bbl	60.58	103.60	(42)	51.20	96.16	(47)
Natural gas – \$/Mcf	2.91	7.60	(62)	3.77	8.57	(56)
Barrels of oil equivalent –	41.74	64.66	(35)	35.33	63.37	(44)
DOWNSTREAM OPERATING RESULTS						
Refining throughput – crude charged – bbl/d	7,076	9,239	(23)	7,696	9,465	(19)
Refinery utilization (%)	75	97	(23)	81	100	(19)
Margins (%)	8	2	300	7	1	600
COMMON SHARES OUTSTANDING						
Weighted average						
Basic	403,565	211,093	91	294,463	210,663	40
Diluted	424,058	213,174	99	294,869	213,286	38
End of period						
Issued				403,567	211,182	91
Diluted				439,945	250,738	75

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

(2) The recognition of bitumen sales from Great Divide Pod One commenced March 1, 2008, when it was declared “commercial”. Prior thereto, all operating costs, net of revenues, were capitalized.

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

(4) Product pricing exclude realized financial derivative gains/losses and unrealized mark-to-market non-cash accounting gains/losses.

Your company made considerable progress during the third quarter 2009 (“Q3 2009”). Buoyed by successful financing activity in the prior quarter and continuing improvements in the operating and financial conditions for our industry, in early July 2009 we were able to reactivate construction at Algar, our second 10,000 bbl/d steam-assisted gravity drainage (“SAGD”) project at our Great Divide oil sands property in northeastern Alberta. It will be recalled we decided to suspend construction at Algar in December 2008. After having completed much of our civil work, including road and plant site construction, we waited on an improvement in industry conditions and confirmation that we had sufficient

funding and liquidity to reactivate construction. We were anxious to reactivate as we had considerable capital already invested in long lead items.

Our construction program has proceeded most favorably, aided by generally favorable weather conditions and despite having lost a number of days of work due to rain. We are currently on time, on or under budget and have also benefited from our prior experience in constructing Pod One. Drilling of the seventeen SAGD well pairs associated with Algar has gone very well, with new records set for drilling time per well. We took advantage of the Algar hiatus to re-engineer the Algar SAGD drilling and completion programs to incorporate the latest knowledge and we have had access to top line equipment and personnel. Also, full credit is due to our own construction team and suppliers of the various services we require to build a plant and complete a project of this nature in a remote region.

Barring anything unforeseen weather-wise over the winter months, we believe that we will complete Algar in April 2010. Thereafter, we will require approximately 30 days to commission the plant, approximately 90 days to steam the SAGD well pairs and associated reservoir and then we anticipate starting ramp up of bitumen production towards plant capacity, which we hope to realize in late 2010 or early 2011.

Thereafter, if crude oil prices remain buoyant with two plants working effectively we should see new record operating and financial results. This will also allow us to spread related financing charges over a broader operating base. We can then focus on operational excellence criteria including continued lowering of unit operating costs and optimizing plant efficiency. Lower natural gas prices will assist us in this regard and once commerciality is achieved at Algar, we will be booking these results in our financial and operating accounts. Until that time, all Algar-related revenues and expenses, including general and administrative and interest costs, will be capitalized.

We are also pleased to report that our total production from Pod One has now exceeded four million barrels of bitumen. During Q3 2009 we completed a successful turnaround at Pod One, including the work over of several well pairs, installation of one additional electrical submersible pump ("ESP") and we cleaned out all vessels at the facility. We now have six ESPs in total installed and operating in our wells. We expect to install a new generation of high-temperature ESPs in some of our wells in early 2010.

Our production performance at Pod One continued to be constrained by minor upsets and challenges throughout the third quarter 2009, the downtime for the turnaround and to some extent post turnaround, when we encountered new water quality and water treatment issues upon restarting of production. We are confident we can overcome these challenges. Overall, our performance continues to be industry acceptable or better, based on our knowledge of the results being achieved in the various SAGD operations but we continue to strive to do better. Our wells have increasingly shown unique characteristics. Our overall productivity is a function of our steam generating capacity and its effective distribution within the reservoir. Increased experience will allow us to better understand each well's productive capacity and the remedial alternatives to optimize plant utilization. This learning will also assist us at Algar, which may be better than Pod One based on early SAGD drilling results, at the outset of our oil sands productions efforts.

Beyond Algar, we continue to advance our development initiatives at our Great Divide SAGD Expansion Project, as embodied in the filing of a Proposed Terms of Reference, which occurred in March 2009. This is the first step in the process of submitting an Environmental Impact Assessment ("EIA") with a view to expanding the design capacity of our SAGD facilities from 20,000 bbl/d to the next level of 44,000 bbl/d. Our longer term goal remains to surpass 50,000 bbl/d by 2015. Achievement of this objective will be reinforced by positive results anticipated from our planned 50 plus core hole drilling program at Great Divide and Halfway Creek during the first quarter 2010 ("Q1 2010") following freeze-up. We applaud recent indications that the regulatory review timetable for SAGD expansion applications may be compressed and expedited, which seems warranted in light of the rather small footprint for SAGD projects compared to mining operations in the oil sands.

Our conventional activities were relatively muted during the summer months, although we did take the opportunity to complete necessary workovers, turnarounds and facility reconstruction, primarily at Battrum, Saskatchewan. Better crude oil prices and, of late, improving natural gas prices have resulted in an improvement in conventional operating and financial results.

Our refining and marketing group reported constructive results during the third quarter and year-to-date, with stronger asphalt prices and favorable refining netbacks until September 2009 when we initiated our first turnaround in over three years. The contribution to overall netbacks from our refining operations continued, even though heavy crude oil price differentials have been narrower than historical averages and asphalt sales volumes have been lower than expected due to poor weather during the early part of the road paving season this year. Again, this was in part because of the "island" market in which we operate, although weak overall economic activity was a constraining factor. We continue to believe our integrated approach is valid and will result in more reliable overall corporate netbacks expressed on a "per barrel of bitumen" produced.

During Q3 2009, we reinforced our investment in Petrolifera Petroleum Limited by essentially maintaining our equity interest in that company, which raised \$58 million of new funds with the sale of shares and warrants from treasury. We continue to believe Petrolifera has vast potential in its wide ranging holdings in South America, especially in Peru and Colombia.

We are most mindful of the need to retain a high level of liquidity and a strong balance sheet while we conduct our extensive construction program at Algar. We recently were successful in securing commitments for a new US\$50 million revolving credit facility from a strong syndicate of Canadian and international banks and are in the process of finalizing the documentation for this facility. It will provide the company with another degree of financial flexibility. Securing this facility is a further indication of the positive light in which the company is held in financial markets. We are also pleased to see the rapid and significant improvement in the market pricing of our outstanding debt instruments, which reflects both the improvement in overall industry conditions and Connacher's performance. We are hopeful that this confidence will now be demonstrated in equity markets in coming months, as Algar completion becomes more visible.

We recently announced the promotion of Merle Johnson to the position of Vice President, Engineering and congratulate Merle on his advancement within the company. He will report to Peter Sametz, Executive Vice President and Chief Operating Officer. Also, we promoted Cameron M. Todd to the position of Senior Vice President, Operations reporting to Mr. Sametz and assigned Russ Longley new head office responsibility for our refining activity, in addition to his continuing role managing our conventional production. Congratulations are extended to these gentlemen.

Connacher's fourth quarter outlook is focused on Pod One production and Algar construction. We are entering into a weak period for refining and marketing but crude oil prices are strong and we hope to continue to report good results from our upstream operations. At this juncture, Algar seems to be proceeding favorably. We will continue to examine crude oil and capital markets for appropriate hedging alternatives to provide stable results in an increasingly volatile world, especially during periods of high capital outlays such as we are presently experiencing. At the same time, we want to ensure our shareholders benefit from rising crude oil prices, the impact of which has been somewhat constrained by the strong Canadian dollar, which helps our earnings and the carrying cost of our U.S. dollar debt but limits the overall impact of higher WTI prices.

Next year, we envisage a capital budget of approximately \$274 million, with completion of Algar the dominant capital program. Our 2010 budget and outlook is discussed in greater detail in our attached Management's Discussion and Analysis ("MD&A"), wherein we also provide updates on our 2010 financial outlook which we provided when we raised additional capital this year. We believe we have sufficient funding from cash balances, anticipated cash flow from operations before working capital adjustments and available credit to not only complete Algar but also the related

facilities (power cogeneration and transfer lines) and conduct our core hole and 3D seismic programs, drill certain conventional exploratory wells in natural gas prone areas and carry out mandated capital programs at our refinery in Great Falls, Montana. We do not otherwise provide formal guidance or forecasts.

We have discerned a marked rise in the "investor interest index" for the oil sands, since the price of WTI passed the US\$70 level. We have had numerous discussions with "interested" parties about possible business relationships, such as joint ventures, aimed at allowing new investors to participate with us in not only developing our properties at an expanded pace, but also expanding theirs and our overall involvement in the oil sands. We have earned recognition for what we have accomplished as a builder and producer in the oil sands and companies with capital and a desire to have long-run oil sands involvement are attracted to us for our expertise in the space. We will continue to dialogue and to monitor opportunities to advance the interests of our shareholders.

Our goals are clear. Our assets are substantial. Our finances are strong. Our projects are advancing. We intend to keep our eye on the prize as we move into the next decade and anticipate this would translate into share price improvement of considerable magnitude going forward. We appreciate the strong and unwavering support of our extensive shareholder base, including that of the significant new institutional shareholders who invested in the company during the year.

Forward Looking Information

This press release contains forward-looking information including but not limited to expectations relating to the construction, commissioning and steam circulation prior to commencement of commercial production at Algar (including the timeline and capital costs associated therewith), planned optimization activities, anticipated future operating and financial results, estimated future production (including anticipated 2010 production levels and the timing of achieving bitumen production approaching plant design capacity from Pod One and Algar) and production goals for 2015, and 2010 capital expenditures, development of additional oil sands resources and internally-generated growth prospects, sources of funding planned capital expenditures and current financial obligations, utilization of alternative financial derivative strategies to protect the company's cash flow and current plans to enter into a new \$50 million banking credit facility, discussions regarding possible business relationships or joint venture arrangements to accelerate the development of the company's oil sands resources and anticipated potential appreciation in Connacher's investment in Petrolifera. Additional forward looking information including forecast 2010 financial outlook is contained in the Management's Discussion and Analysis ("MD&A") attached to this press release. See "Forward Looking Information" in the MD&A.

Forward looking information is based on management's expectations regarding future growth, results of operations, production, future commodity prices and foreign exchange rates, future capital and other expenditures (including the amount, nature and sources of funding thereof), plans for and results of drilling activity, environmental matters, business prospects and opportunities and future economic conditions. Forward-looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated. These risks include, but are not limited to: the risks associated with the oil and gas industry (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve and resource estimates, the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks), the risk of commodity price and foreign exchange rate fluctuations, risks associated with the impact of general economic conditions, risks and uncertainties associated with securing and maintaining the necessary regulatory approvals and financing to proceed with the operation and continued expansion of the Great Divide Oil Sands Project. In addition, the recent financial crisis has resulted in severe economic uncertainty and resulting illiquidity and volatility in credit and capital markets, which increases the risk that actual results will vary from forward looking expectations in this report and these variations may be material. There can be no assurance that the company will be able to complete its proposed \$50 million credit facility documentation or secure alternative sources of liquidity if required. The 2010 financial outlook contained in the MD&A is based on certain assumptions regarding revenue (including production levels, refinery throughput, commodity prices, differentials, quality of bitumen produced, foreign exchange rates and transportation costs), operating and other costs, royalties and general and administrative costs which are detailed in the notes to the tables contained in the MD&A. Actual netbacks and adjusted EBITDA realized by Connacher in 2010 could differ materially from the estimates contained in the 2010 financial outlook. Material risks and uncertainties that may impact achievement of the 2010

netbacks and adjusted EBITDA are described in the MD&A. Additional risks and uncertainties affecting Connacher and its business and affairs are described in further detail in Connacher's Annual Information Form for the year ended December 31, 2008, which is available at www.sedar.com. Although Connacher believes that the expectations in such forward-looking information are reasonable, there can be no assurance that such expectations shall prove to be correct. The forward-looking information included in this report are expressly qualified in their entirety by this cautionary statement. The forward-looking information included in this report is made as of November 11, 2009 and Connacher assumes no obligation to update or revise any forward-looking information to reflect new events or circumstances, except as required by law.

For further information, contact:

R. A. Gusella

President and Chief Executive Officer

Or

Grant D. Ukrainetz

Vice President, Corporate Development

Phone: 403 538-6201

Fax: 403 – 538-6225

inquiries@connacheroil.com

www.connacheroil.com

Suite 900, 332 – 6th Avenue S.W.
Calgary, Alberta T2P 0B2
Telephone: (403) 538-6201 Facsimile: (403) 538-6225

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is dated as of November 11, 2009 and should be read in conjunction with the unaudited consolidated financial statements of Connacher Oil and Gas Limited ("Connacher" or the "company") for the nine months ended September 30, 2009 and 2008 as contained in this interim report and the MD&A and audited consolidated financial statements for the years ended December 31, 2008 and 2007, as contained in the company's 2008 annual report. All of these consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and are presented in Canadian dollars. This MD&A provides management's view of the financial condition of the company and the results of its operations for the reporting periods. Additional information relating to Connacher, including Connacher's Annual Information Form is on SEDAR at www.sedar.com.

NON-GAAP MEASUREMENTS

The MD&A contains terms commonly used in the oil and gas industry, such as cash flow, cash flow per share, cash operating netback, bitumen netback, conventional netback, refinery netback, corporate netback and adjusted earnings before interest, taxes, depreciation and amortization ("EBITDA"). These terms are not defined by GAAP and should not be considered an alternative to, or more meaningful than, cash provided by operating activities or net earnings as determined in accordance with GAAP as an indicator of Connacher's performance. Management believes that in addition to net earnings, cash flow, netbacks and adjusted EBITDA are useful financial measurements which assist in demonstrating the company's ability to fund capital expenditures necessary for future growth or to repay debt. Connacher's determination of cash flow, operating netbacks and adjusted EBITDA may not be comparable to that reported by other companies. All references to cash flow throughout this report are based on cash flow from operating activities before changes in non-cash working capital, pension funding and asset retirement expenditures. The company calculates cash flow per share by dividing cash flow by the weighted average number of common shares outstanding. Netbacks, including by product, are calculated by deducting the related diluent, transportation, field operating costs and royalties from revenues before deducting MTM accounting gains/losses. Adjusted EBITDA is calculated as net earnings before interest, taxes, depreciation and amortization. Cash flow and netbacks are reconciled to net earnings within this MD&A. Future anticipated netbacks and adjusted EBITDA will be reconciled to net earnings in the applicable MD&A on a quarterly basis in 2010.

FORWARD-LOOKING INFORMATION

This report, including the Letter to Shareholders and the updated 2010 financial outlook contained in the MD&A, contains forward-looking information including but not limited to expectations relating to the construction, commissioning and steam circulation prior to commencement of commercial production at Algar (including the timeline and capital costs associated therewith), anticipated future operating and financial results, estimated future production (including anticipated 2010 production levels and the timing of achieving bitumen production approaching plant design capacity from Algar) and production goals for 2015, forecast netbacks, corporate general and administration expenses, adjusted EBITDA, profitability and fourth quarter 2009 and 2010 capital expenditures, development of additional oil sands resources and internally-generated growth prospects, sources of funding planned capital expenditures and current financial obligations, utilization of alternative financial derivative strategies to protect the company's cash flow and current plans to enter into a new \$50 million banking credit facility and discussions regarding possible business relationships or joint venture arrangements to accelerate the development of the company's oil sands resources. Forward looking information is based on management's expectations regarding future growth, results of operations, production, future commodity prices and foreign exchange rates, future capital and other expenditures (including the amount, nature and sources of funding thereof), plans for and results of drilling activity, environmental matters, business prospects and opportunities and future economic conditions. Forward-looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated. These risks include, but are not limited to: the risks associated with the oil and gas industry (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve and resource estimates, the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks), the risk of commodity price and foreign exchange rate fluctuations, risks associated with the impact of general economic conditions, risks and uncertainties associated with securing and maintaining the necessary regulatory approvals and financing to proceed with the operation and continued expansion of the Great Divide Oil Sands Project. In addition, the recent financial crisis has resulted in severe economic uncertainty and resulting illiquidity and volatility in credit and capital markets, which increases the risk that actual results will vary from forward looking expectations in this report and these variations may be material. There can be no assurance that the company will be able to complete its proposed \$50 million credit facility documentation or secure alternative sources of liquidity if required. The 2010 financial outlook contained in the MD&A is based on certain assumptions regarding revenue (including production levels, refinery throughput, commodity prices, differentials, quality of bitumen produced, foreign exchange rates and transportation costs), operating and other costs, royalties and general and administrative costs which are detailed in the notes to the tables contained in the MD&A. Actual netbacks and adjusted EBITDA realized by Connacher in 2010 could differ materially from the estimates contained in the 2010 financial outlook. Material risks and uncertainties that may impact achievement of the 2010 netbacks and adjusted EBITDA are described in this MD&A. Additional risks and uncertainties affecting Connacher and its business and affairs are described in further detail in Connacher's Annual Information Form for the year ended December 31, 2008, which is available at www.sedar.com. Although Connacher believes that the expectations in such forward-looking information are reasonable, there can be no assurance that such expectations shall prove to be correct. The forward-looking information included in this report are expressly qualified in their entirety by this cautionary statement. The forward-looking information included in this report is made as of November 11, 2009 and Connacher assumes no obligation to update or revise any forward-looking information to reflect new events or circumstances, except as required by law.

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

SUMMARIZED HIGHLIGHTS

	Three months ended		Nine months ended	
	September 30		September 30	
	2009	2008	2009	2008
FINANCIAL				
(\$000)				
Upstream revenues, net of royalties ⁽¹⁾	\$ 58,709	\$ 96,291	\$ 120,737	\$ 207,700
Downstream revenues ⁽¹⁾	92,714	127,726	194,960	317,445
Upstream cash operating netback ^(1,2)	12,319	35,878	30,213	80,990
Downstream margin ⁽¹⁾	7,699	2,271	13,614	2,671
Cash flow	10,410	31,130	15,288	59,505
Net earnings (loss)	47,767	12,139	40,889	16,989
Cash on hand			333,634	236,375
Working capital			347,139	200,177
Total assets			1,736,126	1,369,533

OPERATING

Upstream production/sales volumes				
Oil sands – bitumen – bbl/d	6,551	6,810	6,336	4,909
Crude oil – bbl/d	993	957	1,095	976
Natural gas – Mcf/d	10,377	13,188	11,774	12,625
Barrels of oil equivalent – boe/d	9,274	9,966	9,394	7,990
Upstream cash operating netback/boe ^(1,2)	\$ 14.44	\$ 39.13	\$ 11.10	\$ 37.38
Downstream				
Crude charged – bbl/d	7,076	9,329	7,696	9,465
Downstream margin per barrel refined	\$ 7.16	\$ 2.00	\$ 5.52	\$ 0.87
Downstream margins as a percentage of revenue – %	8	2	7	1

(1) Includes sales between business segments which are eliminated for financial statement reporting purposes.

(2) Excluding unrealized non-cash mark-to-market accounting gains and losses.

MARKETING – UPSTREAM

Diluted bitumen (“dilbit”), crude oil and natural gas are generally sold on month-to-month sales contracts negotiated with major Canadian or U.S. marketers, refiners or other end users, at either spot reference prices or at prices subject to commodity contracts based on WTI for crude oil and AECO for natural gas. As a means of managing the risk of commodity price volatility, Connacher enters into financial derivative commodity price-hedging contracts from time to time.

At November 11, 2009, Connacher had the following WTI crude oil price-hedging contracts in place:

- April 1, 2009 – December 31, 2009 – 2,500 bbl/d – WTI US\$49.50/bbl;
- September 1, 2009 – December 31, 2009 – 2,500 bbl/d – minimum of WTI US\$60.00/bbl and a maximum of WTI US\$84.00/bbl; and
- Calendar year 2010 – 2,500 bbl/d – WTI US\$78.00/bbl.

As at September 30, 2009, the WTI crude oil forward price curve exceeded the hedging contract prices, resulting in a current liability and an unrealized mark-to-market (“MTM”) non-cash accounting loss of \$1.8 million for these contracts. For the year-to-date, the opportunity cost or realized losses on these contracts totalled \$14 million. These losses are deducted from reported upstream revenues.

Additionally, in order to mitigate foreign exchange exposure to commodity pricing, Connacher entered into a foreign exchange revenue collar which throughout 2009 sets a floor of CAD\$1.1925 per US\$1.00 and a ceiling of CAD\$1.30 per US\$1.00 on a notional amount of US\$10 million of monthly production revenue. For clarity, this contract provides the company a benefit from a strengthening Canadian dollar. As at September 30, 2009, based on the forward foreign exchange rate curve, the foreign exchange revenue collar had a value of \$3.4 million; at December 31, 2008 it had a value of \$1.8 million. The change in these values resulted in an unrealized non-cash foreign exchange gain of \$1.6 million in the first nine months of 2009. Additionally, in the first nine months of 2009, Connacher realized a hedging gain (and received cash) in the amount of \$3.9 million on this contract. These cash gains are included in foreign exchange gains/losses.

During the first nine months of 2009, Connacher also entered into a six-month term contract for the sale of dilbit to a company operating a bitumen upgrader in northern Alberta and had a WTI crude oil swap contract from February 1, 2009 to August 31, 2009 on 2,500 bbl/d at US\$46.00/bbl.

MARKETING – DOWNSTREAM

Sales of refined products are generally made on monthly sales contracts negotiated with wholesalers, retailers and large end-users for gasoline, jet fuel and diesel and construction contractors and road builders for asphalt. Occasionally, sales contracts are for periods in excess of one month. To date, Connacher has not hedged these revenue streams as the “island” market we operate in makes it difficult to enter into effective hedge programs without incurring significant basis risk.

PRICING

Together with many other uncontrolled variables, general economic conditions and international and local supplies influence the price for WTI light gravity crude oil. Weather, domestic supplies and other variables influence the market price for natural gas.

In the first nine months of 2009, commodity prices were much lower than in 2008. For example, WTI crude oil averaged US\$57.13/bbl this year (first nine months 2008 – US\$113.29/bbl) and AECO natural gas averaged \$4.09/Mcf (first nine months 2008 – \$8.57/Mcf), well below last year’s levels.

Connacher’s crude oil and bitumen production slate is generally heavier than the referenced WTI. Consequently, the market price realized by the company is typically lower than WTI.

Before hedging gains and unrealized MTM non-cash accounting gains and losses, Connacher realized the following commodity selling prices:

	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
Bitumen – \$/bbl	\$ 45.30	\$ 65.34	\$ 36.53	\$ 61.98
Crude oil – \$/bbl	60.58	103.60	51.20	96.16
Natural gas – \$/Mcf	2.91	7.60	3.77	8.57

Refined product selling prices are also influenced by general economic conditions and local and international supply and demand factors. Average prices realized by the company in the three and nine months ended September 30, 2009 and 2008 were much lower, as noted below.

	MRCI Realized Selling Price (U.S.\$/bbl)			
	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
Gasoline	\$ 80.79	\$ 129.25	\$ 67.17	\$ 121.38
Diesel	75.90	144.79	67.90	137.03
Jet fuel	87.35	166.35	80.42	155.36
Asphalt	78.22	63.72	72.85	59.09

These lower refined product prices were consistent with lower WTI crude prices, except for asphalt, prices for which were higher in Q3 09 and in the 2009 year-to-date due to increased asphalt product demand. During the summer of 2009, MRCI sold asphalt at higher prices than ever before. Some unfilled asphalt orders are anticipated to be carried over into the summer of 2010.

FINANCIAL AND OPERATING REVIEW

Details of Connacher’s operating results, by business segment, are presented below. These segment results include revenues and expenses from inter-segment sales which have been eliminated upon consolidation for financial statement reporting purposes. These inter-segment eliminations are detailed in Note 8 to the interim financial statements, included in this Quarterly Report.

UPSTREAM NETBACKS (\$000)

For the three months ended September 30, 2009	Oil Sands	Crude Oil	Natural Gas	Total
Gross revenues ⁽²⁾	\$ 45,665	\$ 5,642	\$ 2,775	\$ 54,082
Diluent purchased ⁽³⁾	(15,317)	-	-	(15,317)
Transportation costs	(3,050)	(105)	-	(3,155)
Production revenue	27,298	5,537	2,775	35,610
Realized financial derivative gains (losses) ⁽⁴⁾	(8,311)	-	-	(8,311)
Unrealized mark-to-market accounting gains (losses) ⁽⁵⁾	14,753	-	-	14,753
Royalties	(1,088)	(1,516)	789	(1,815)
Operating costs	(10,194)	(778)	(2,193)	(13,165)
Calculated netback	\$ 22,458	\$ 3,243	\$ 1,371	\$ 27,072
Cash operating netback, excluding unrealized mark-to-market accounting gains and losses ⁽⁶⁾	\$ 7,705	\$ 3,243	\$ 1,371	\$ 12,319

For the three months ended September 30, 2008	Oil Sands ⁽¹⁾	Crude Oil	Natural Gas	Total
Gross revenues ⁽²⁾	\$ 80,604	\$ 9,121	\$ 9,223	\$ 98,948
Diluent purchased ⁽³⁾	(33,409)	-	-	(33,409)
Transportation costs	(6,256)	-	-	(6,256)
Production revenue	40,939	9,121	9,223	59,283
Realized financial derivative gains (losses) ⁽⁴⁾	-	-	(427)	(427)
Unrealized mark-to-market accounting gains (losses) ⁽⁵⁾	-	-	2,032	2,032
Royalties	(414)	(2,675)	(1,173)	(4,262)
Operating costs	(15,782)	(1,736)	(1,198)	(18,716)
Calculated netback	\$ 24,743	\$ 4,710	\$ 8,457	\$ 37,910
Cash operating netback, excluding unrealized mark-to-market accounting gains and losses ⁽⁶⁾	\$ 24,743	\$ 4,710	\$ 6,425	\$ 35,878

For the nine months ended September 30, 2009	Oil Sands	Crude Oil	Natural Gas	Total
Gross revenues ⁽²⁾	\$ 114,907	\$ 15,568	\$ 12,112	\$ 142,587
Diluent purchased ⁽³⁾	(43,352)	-	-	(43,352)
Transportation costs	(8,374)	(263)	-	(8,637)
Production revenue	63,181	15,305	12,112	90,598
Realized financial derivative gains (losses) ⁽⁴⁾	(14,068)	-	-	(14,068)
Unrealized mark-to-market accounting gains (losses) ⁽⁵⁾	(1,757)	-	-	(1,757)
Royalties	(1,305)	(4,010)	(710)	(6,025)
Operating costs	(29,985)	(3,029)	(7,278)	(40,292)
Calculated netback	\$ 16,066	\$ 8,266	\$ 4,124	\$ 28,456
Cash operating netback, excluding unrealized mark-to-market accounting gains and losses ⁽⁶⁾	\$ 17,823	\$ 8,266	\$ 4,124	\$ 30,213

For the nine months ended September 30, 2008	Oil Sands ⁽¹⁾	Crude Oil	Natural Gas	Total
Gross revenues ⁽²⁾	\$ 165,843	\$ 25,723	\$ 29,640	\$ 221,206
Diluent purchased ⁽³⁾	(72,784)	-	-	(72,784)
Transportation costs	(9,684)	-	-	(9,684)
Production revenue	83,375	25,723	29,640	138,738
Realized financial derivative gains (losses) ⁽⁴⁾	-	-	(831)	(831)
Unrealized mark-to-market accounting gains (losses) ⁽⁵⁾	-	-	-	-
Royalties	(874)	(7,220)	(4,581)	(12,675)
Operating costs	(35,466)	(3,606)	(5,170)	(44,242)
Calculated netback	\$ 47,035	\$ 14,897	\$ 19,058	\$ 80,990
Cash operating netback, excluding unrealized mark-to-market accounting gains and losses ⁽⁶⁾	\$ 47,035	\$ 14,897	\$ 19,058	\$ 80,990

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

(2) Bitumen produced at Great Divide Pod One is mixed with purchased diluent and sold as "dilbit". Diluent is a light hydrocarbon that improves the marketing and transportation quality of bitumen. In the financial statements Upstream Revenues represent sales of dilbit, crude oil and natural gas, net of royalties; and Upstream Operating Costs include the cost of purchased diluent.

(3) Diluent volumes purchased and sold have been deducted in calculating production revenue and production volumes sold.

(4) Realized financial derivative gains/losses reflect cash receipts/disbursements in respect of financial derivative commodity price-hedging contracts.

(5) Unrealized mark-to-market ("MTM") accounting gains/losses reflect changes in the market value of unsettled commodity price derivative contracts. From period to period the market value of these contracts change due to the volatility of the commodity's forward pricing curve and the reducing period to maturity of these contracts.

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

UPSTREAM SALES AND PRODUCTION VOLUMES

For the three months ended September 30	2009	2008	% Change
Dilbit sales – bbl/d ⁽¹⁾	8,666	9,492	(9)
Diluent purchased – bbl/d ⁽¹⁾	(2,115)	(2,682)	(21)
Bitumen produced and sold – bbl/d ⁽¹⁾	6,551	6,810	(4)
Crude oil produced and sold – bbl/d	993	957	4
Natural gas produced and sold – Mcf/d	10,377	13,188	(22)
Total – boe/d	9,274	9,966	(7)

For the nine months ended September 30	2009	2008	% Change
Dilbit sales – bbl/d ⁽¹⁾	8,571	6,790	26
Diluent purchased – bbl/d ⁽¹⁾	(2,235)	(1,881)	19
Bitumen produced and sold – bbl/d ⁽¹⁾	6,336	4,909	29
Crude oil produced and sold – bbl/d	1,095	976	12
Natural gas produced and sold – Mcf/d	11,774	12,625	(7)
Total – boe/d	9,394	7,990	18

(1) Since declaring Great Divide Pod One "commercial" effective March 1, 2008.

UPSTREAM NETBACKS PER UNIT OF PRODUCTION

For the three months ended September 30, 2009	Bitumen (\$ per bbl)	Crude Oil (\$ per bbl)	Natural Gas (\$ per Mcf)	Total (\$ per boe)
Production revenue	\$ 45.30	\$ 60.58	\$ 2.91	\$ 41.74
Realized financial derivative gains (losses)	(13.79)	-	-	(9.74)
Unrealized mark-to-market accounting gains (losses)	24.48	-	-	17.30
Royalties	(1.81)	(16.59)	0.83	(2.13)
Operating costs	(16.92)	(8.51)	(2.30)	(15.43)
Calculated netback	\$ 37.26	\$ 35.48	\$ 1.44	\$ 31.74
Cash operating netback, excluding unrealized mark-to-market accounting gains and losses	\$ 12.78	\$ 35.48	\$ 1.44	\$ 14.44

For the three months ended September 30, 2008

Production revenue	\$ 65.34	\$ 103.60	\$ 7.60	\$ 64.66
Realized financial derivative gains (losses)	-	-	(0.35)	(0.47)
Unrealized mark-to-market accounting gains (losses)	-	-	1.67	2.22
Royalties	(0.66)	(30.38)	(0.97)	(4.65)
Operating costs	(25.19)	(19.72)	(0.99)	(20.41)
Calculated netback	\$ 39.49	\$ 53.50	\$ 6.96	\$ 41.35
Cash operating netback, excluding unrealized mark-to-market accounting gains and losses	\$ 39.49	\$ 53.50	\$ 5.29	\$ 39.13

For the nine months ended September 30, 2009	Bitumen (\$ per bbl)	Crude Oil (\$ per bbl)	Natural Gas (\$ per Mcf)	Total (\$ per boe)
Production revenue	\$ 36.53	\$ 51.20	\$ 3.77	\$ 35.33
Realized financial derivative gains (losses)	(8.13)	-	-	(5.49)
Unrealized mark-to-market accounting gains (losses)	(1.02)	-	-	(0.68)
Royalties	(0.75)	(13.41)	(0.22)	(2.35)
Operating costs	(17.34)	(10.13)	(2.26)	(15.71)
Calculated netback	\$ 9.29	\$ 27.66	\$ 1.29	\$ 11.10
Cash operating netback, excluding unrealized mark-to-market accounting gains and losses	\$ 10.31	\$ 27.66	\$ 1.29	\$ 11.78

For the nine months ended September 30, 2008

Production revenue	\$ 61.98	\$ 96.16	\$ 8.57	\$ 63.37
Realized financial derivative losses	-	-	(0.24)	(0.38)
Unrealized mark-to-market losses	-	-	-	-
Royalties	(0.65)	(27.00)	(1.32)	(5.78)
Operating costs	(26.37)	(13.48)	(1.50)	(20.21)
Calculated netback	\$ 34.96	\$ 55.68	\$ 5.51	\$ 37.00
Cash operating netback, excluding unrealized mark-to-market accounting gains and losses	\$ 34.96	\$ 55.68	\$ 5.75	\$ 37.38

In response to a collapse in crude oil prices and widening of heavy oil differentials, the company announced in December 2008 that it had curtailed production at Pod One from levels that had exceeded 9,000 bbl/d earlier in that month, through the reduction of steam to be injected into the bitumen reservoir. On January 21, 2009, the company announced the resumption of full production ramp-up at Pod One in anticipation of the reinstatement of profitability at Pod One, as a result of improved product prices; in response to narrower heavy oil pricing differentials; reduced transportation costs; anticipated reduced diluent blending ratios due to increased dilbit sales to upgraders operating near our SAGD oil sands facility and due to WTI crude oil hedges entered into, that provided some protection against further weakness in selling prices.

Although year-to-date 2009 bitumen production volumes are higher than the prior year, they are below expectation due to the curtailment of production, as noted above, operational upsets which we have found to be common in the business and a four-day shut-down in September 2009, for our annual maintenance turnaround. The company is again restoring normal operations and ramping up its bitumen production although it has encountered what we believe to be resolvable water quality issues in recent days. Crude oil production volumes have been slightly higher in the current year than in 2008 due to successful drilling and field maintenance programs. However, natural gas sales volumes are down from 2008, due to natural production declines, as the company reduced its drilling and development program in response to the low natural gas price environment.

In the third quarter of 2009, gross upstream revenues of \$54 million were 46 percent lower than the \$99 million reported in the third quarter of 2008. This was primarily due to lower commodity prices (WTI averaged US\$67.72 in the current quarter compared to US\$118.59 in the third quarter of 2008, a 43 percent drop and AECO natural gas prices averaged \$3.18/mcf in the third quarter of 2009 compared to \$7.80/mcf in the third quarter of 2008, a 59 percent drop) and lower production volumes noted above.

Relative to previously reported Q2 2009 gross upstream revenues of \$50 million, Q3 2009 revenues benefited from slightly higher oil prices, while production volumes were relatively unchanged.

For the year-to-date, gross upstream revenues of \$143 million were 35 percent lower than the \$221 million of revenue reported in the comparable 2008 period. Again, this reduction was primarily driven by lower commodity prices, as WTI was lower by 42 percent and AECO was lower by 52 percent, year-over-year, offset somewhat by higher production volumes in the current year.

Royalties represent charges against production or revenue by governments and landowners. Royalties in the third quarter of 2009 were \$1.8 million compared to \$4.3 million in the third quarter of 2008 and royalties for the first nine months of 2009 were \$6 million compared to \$13 million in the first nine months of 2008. From year to year, royalties can change based on changes in the product mix, the components of which are subject to different royalty rates. Additionally, royalty rates are applied on a sliding scale to commodity prices. The most notable change in royalties this year came as a result of reduced product pricing and natural gas cost allowance recoveries received from the Alberta Government stemming from a reduction of Connacher's 2008 Alberta Crown corporate effective royalty rate. Gas cost allowances recorded in the third quarter of 2009 resulted in the recovery of more natural gas crown royalties from prior periods than were payable in the quarter.

In Q3 2009, upstream diluent purchases of \$15 million (year-to-date \$43 million) were required for our oil sands operations. These purchases include \$2 million (\$6 million year-to-date) of diluent purchased from our subsidiary, Montana Refining Company, Inc. which are included in our netback calculations. However, for financial statement presentation purposes, these intercompany purchases were eliminated on consolidation. In the third quarter of 2008, diluent purchases were \$33 million (2008 year-to-date \$73 million). There were no intercompany purchases in the prior year periods. Bitumen produced at Great Divide is mixed with purchased diluent and sold as "dilbit." Diluent is a light liquid hydrocarbon that enables the marketing and transportation of bitumen. For the reported volumes in Q3 2009, diluent purchased represented approximately 24 percent of the dilbit barrel sold, with bitumen the remaining 76 percent; in Q3 2008 these splits were 28 percent and 72 percent, respectively. The price of diluent closely tracks crude oil prices. Diluent costs were lower in the third quarter and year-to-date 2009 relative to the comparative 2008 periods, while comparative volumes changed only slightly.

Field operating costs of \$13 million in Q3 2009 were substantially lower than the \$19 million reported in the third quarter of 2008, as a result of our concerted efforts to reduce costs and optimize our production processes.

Total oil sands field operating costs of \$10 million in Q3 2009 resulted in an average of \$16.92 per barrel of bitumen produced, 32 percent lower than the per barrel cost last year. Although lower natural gas costs contributed, reductions in other cost components were also realized from our optimization strategy.

Transportation costs of \$3 million in Q3 2009 were lower than the \$6 million recorded in Q3 2008, primarily due to successful marketing arrangements in selling similar volumes to closer markets.

Realized financial derivative losses of \$8 million in the third quarter of 2009 and \$14 million in the 2009 year-to-date compared to a \$427,000 loss in Q3 2008 and \$831,000 loss in the 2008 year-to-date. Unrealized MTM non-cash accounting gains of \$15 million in Q3 2009 and a loss of \$2 million in the 2009

year-to-date compared to a gain of \$2 million in Q3 2008 and nil for the first nine months of 2008, as a result of commodity prices being different than our commodity price contracts. The details of these contracts are noted in Marketing-Upstream, herein. These gains and losses are included in our reported revenues on our Statements of Operations.

Netbacks are a widely used industry measure of a company's efficiency and its ability to internally fund its growth. The company's overall Q3 2009 upstream cash operating netback, excluding MTM accounting gains and losses was \$12 million (\$14.44/boe) and \$30 million (\$11.78/boe) for the year-to-date 2009, compared to \$36 million (\$39.13/boe) in the Q3 2008 and \$81 million (\$37.38/boe) for the first nine months of 2008. Netbacks in 2009 were lower than netbacks in 2008, primarily as a result of lower commodity prices, offset by operational efficiencies, as reflected in lower per unit operating costs.

RECONCILIATION OF UPSTREAM OPERATING NETBACK TO NET EARNINGS

For three months ended September 30 (\$000, except per unit amounts)	2009		2008	
	Total	Per boe	Total	Per boe
Upstream netback, as above	\$ 27,072	\$ 31.74	\$ 37,910	\$ 41.35
Refining margin – net	7,699	9.02	2,271	2.48
Interest and other income	2,189	2.57	541	0.59
General and administrative	(3,364)	(3.94)	(2,774)	(3.03)
Stock-based compensation	(623)	(0.73)	(790)	(0.86)
Finance charges	(13,127)	(15.39)	(7,786)	(8.49)
Foreign exchange (loss) gain	56,344	66.04	(1,439)	(1.57)
Depletion, depreciation and accretion	(16,691)	(19.56)	(14,968)	(16.33)
Income taxes	(6,342)	(7.43)	(1,620)	(1.77)
Equity interest in Petrolifera earnings (loss) and dilution gain (loss)	(5,390)	(6.33)	794	0.87
Net earnings	\$ 47,767	\$ 55.99	\$ 12,139	\$ 13.24

For the nine months ended September 30 (\$000, except per unit amounts)	2009		2008	
	Total	Per boe	Total	Per boe
Upstream netback as above	\$ 28,456	\$ 11.10	\$ 80,990	\$ 37.00
Refining margin – net	13,614	5.31	2,671	1.22
Interest income	3,363	1.31	2,085	0.95
General and administrative	(11,062)	(4.31)	(8,751)	(4.00)
Stock-based compensation	(2,444)	(0.95)	(3,487)	(1.59)
Finance charges	(31,164)	(12.15)	(22,515)	(10.28)
Foreign exchange (loss) gain	93,889	36.61	(6,648)	(3.04)
Depletion, depreciation and accretion	(49,678)	(19.37)	(36,257)	(16.56)
Income taxes	166	0.06	(1,307)	(0.60)
Equity interest in Petrolifera earnings and dilution gain	(4,251)	(1.66)	10,208	4.66
Net earnings (loss)	\$ 40,889	\$ 15.95	\$ 16,989	\$ 7.76

DOWNSTREAM REVENUES AND MARGINS

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

Refinery throughput - three months ended	Sept 30, 2008	Dec 31, 2008	March 31, 2009	June 30, 2009	Sept 30, 2009
Crude charged (bbl/d) ⁽¹⁾	9,239	8,333	6,867	9,145	7,076
Refinery production (bbl/d) ⁽²⁾	10,284	9,075	7,946	10,438	8,131
Sales of produced refined products (bbl/d)	11,897	6,404	5,290	9,222	10,596
Sales of refined products (bbl/d) ⁽³⁾	12,385	7,564	5,890	9,451	11,697
Refinery utilization ⁽⁴⁾	97%	88%	72%	96%	75%

(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.

During Q1 2009, the US\$20 million ultra low sulphur diesel project was completed at the Montana refinery. Due to down time required to tie-in the new hydrogen plant to complete this project and as a result of certain operational upsets due to significant cold weather, throughput volumes were lower in Q4 2008 and Q1 2009 than in other quarters. Throughput volumes were also lower in the third quarter of 2009 due to down time associated with the refinery's triennial major maintenance and "turnaround", which began in mid-September 2009 and was completed in mid-October 2009.

Q3 2009 refining revenues of \$93 million were well below the level realized in Q3 2008 (\$128 million), when refined product selling prices were much higher. Due to these lower selling prices, downstream revenues for the nine months ended September 30, 2009 of \$195 million were significantly less than the \$317 million reported in the first nine months of 2008. Downstream revenues and refining margins as presented in the tables below include intercompany diluent sales of \$2 million in Q3 2009 and \$6 million for the year-to-date 2009. These have been eliminated on consolidation for financial statement presentation purposes. There were no intercompany sales in the prior year periods.

Increased processing throughput and sales volumes and higher selling prices since Q1 2009 have resulted in higher operating margins. General economic conditions also affect refined product demand and pricing and we anticipate they will continue to influence our financial results.

Notwithstanding lower current year sales volumes and pricing, year-to-date downstream margins were higher in the first nine months of 2009 (\$14 million, or seven percent) compared to the first nine months of 2008 (\$3 million or one percent), as crude oil input costs have come down faster in 2009 than selling prices have been reduced.

In Q3 2009, the company sold 500,000 bbls of asphalt at an average selling price of US\$78.22/bbl. This represented more the 60 percent of the company's year-to-date asphalt sales (815,000 bbls) and represented more than 50 percent of the volume of refined products sold in the third quarter. This is consistent with the traditional seasonality of this business, but represents an increase in volume and selling price over Q3 2008 when 420,000 bbls of asphalt were sold at an average price of US\$63.72/bbl.

Feedstocks – three months ended	Sept 30, 2008	Dec 31, 2008	Mar 31, 2009	June 30, 2009	Sept 30, 2009
Sour crude oil	93%	94%	91%	91%	91%
Other feedstocks and blends	7%	6%	9%	9%	9%
Total	100%	100%	100%	100%	100%
Revenues and Margins (\$'000)					
Refining sales revenue	\$ 127,726	\$ 56,803	\$ 33,152	\$ 69,094	\$ 92,714
Refining – crude oil and operating costs	125,455	66,964	30,720	65,611	85,015
Refining margin	\$ 2,271	\$ (10,161)	\$ 2,432	\$ 3,483	\$ 7,699
Refining margin	1.8%	(17.9%)	7%	5%	8%
Sales of Produced Refined Products (Volume %)					
Gasolines	35%	44%	55%	48%	32%
Diesel fuels	19%	25%	22%	11%	8%
Jet fuels	5%	8%	7%	7%	6%
Asphalt	38%	19%	12%	31%	51%
LPG and other	3%	4%	4%	3%	3%
Total	100%	100%	100%	100%	100%
Per Barrel of Refined Product Sold					
Refining sales revenue	\$ 112.10	\$ 81.62	\$ 62.54	\$ 80.34	\$ 86.16
Less: refining – crude oil purchases and operating costs	110.10	96.23	57.95	76.29	79.00
Refining margin	\$ 2.00	\$ (14.61)	\$ 4.59	\$ 4.05	\$ 7.16

INTEREST AND OTHER INCOME

In Q3 2009, the company earned interest of \$393,000 (Q3 2008 – \$541,000; 2009 year-to-date – \$1.1 million; 2008 year-to-date – \$2.1 million) on excess funds invested in secure short-term investments and realized a gain of \$1.8 million on the repurchase of Second Lien Notes in Q3 2009 and \$2.3 million in the year-to-date 2009.

GENERAL AND ADMINISTRATIVE EXPENSES

In Q3 2009, general and administrative ("G&A") expenses were \$3.4 million compared to \$2.8 million in Q3 2008, an increase of 21 percent, reflecting increased staffing and activity levels. Additionally, G&A of \$1.1 million was capitalized in the third quarter of each of 2009 and 2008.

For the first nine months of 2009, G&A expenses were \$11.1 million compared to \$8.8 million in the first nine months of 2008, after capitalizing \$3.7 million in the first nine months of 2009 and \$4.1 million in the first nine months of 2008.

FINANCE CHARGES

Finance charges include interest expense relating to the Convertible Debentures, standby fees associated with the company's undrawn lines of credit, which was cancelled in March 2009, fees on letters of credit issued and a portion of the First and Second Lien Senior Notes interest not attributable to major development/capital projects. Finance charges also include non-cash accretion charges with respect to the Convertible Debentures and a portion of the First and Second Lien Senior Notes.

Finance charges of \$13.1 million in Q3 2009 were \$5.3 million higher than the 2008 comparative period due to a higher proportion of interest expensed. The prior year period also included a non-cash mark-to-market charge on our cross-currency interest rate swap then in place. No such charge applied in 2009, as the cross-currency swap was unwound in the fourth quarter of 2008 for a net cash gain of \$89 million.

Year-to-date finance charges of \$31.2 million are \$8.6 million higher than the 2008 comparative period primarily as a result of higher debt levels since issuing the First Lien Senior Notes in mid-June 2009.

We continued to capitalize interest to our Algar project for that portion of our debt attributed to the project.

STOCK BASED COMPENSATION

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

(\$000)	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
Charged to G&A expense	\$ 623	\$ 790	\$ 2,444	\$ 3,487
Capitalized to property and equipment	162	20	669	1,042
	\$ 785	\$ 810	\$ 3,113	\$ 4,529

The reduction from the prior period is due to a lower fair market value of options being granted in the current year.

FOREIGN EXCHANGE GAINS AND LOSSES

Over the past several months, the value of the Canadian dollar has strengthened relative to the U.S. dollar. This has had a significant impact to Connacher upon translating its U.S. dollar denominated long-term debt and U.S. dollar cash balances into Canadian dollars for financial reporting purposes.

In Q3 2009, we had unrealized foreign exchange translation gains of \$53.5 million (\$87.1 million for the year-to-date). We also realized foreign exchange gains of \$2.8 million in Q3 2009 and \$6.8 million year-to-date 2009 from monthly cash settlement receipts in respect of a foreign exchange revenue collar and upon the settlement of U.S. dollar denominated obligations.

Throughout most of 2008, we had a cross-currency swap in place to hedge one-half of the foreign exchange exposure on our U.S. dollar debt. This insulated us from some foreign currency volatility and reduced the impact of a weaker Canadian dollar, which resulted in the unrealized foreign exchange translation losses reported in the comparative 2008 periods.

Having unwound the cross-currency swap in the fourth quarter of 2008 for a net cash gain of \$89 million, Connacher is now fully exposed to changes in the U.S./Canadian dollar exchange rate when translating its U.S. dollar debt to Canadian dollars for financial reporting purposes, for purposes of paying U.S. denominated interest and for repaying such indebtedness. To mitigate some of this exposure, the company carries some U.S. cash and may in future secure another cross-currency swap, if available.

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

Depletion expense is calculated using the unit-of-production method based on total estimated proved reserves. Refining properties and other assets are depreciated over their estimated useful lives. Effective March 1, 2008 Pod One's accumulated capital costs were added to the depletion pool and have been depleted from that date. DD&A in Q3 2009 was \$16.7 million, and for the first nine months of 2009 was \$49.7 million. These charges were, respectively, 12 percent and 37 percent higher than the 2008 comparative periods, reflecting a full nine months of depletion of Pod One capital costs in 2009. Depletion equates to \$16.30 per boe of production in year-to-date 2009, compared to \$13.58 per boe in year-to-date 2008 comparative period.

Future development costs of \$1.3 billion (2008 – \$995 million) for proved undeveloped reserves were included in the third quarter and year-to-date depletion calculation. Capital costs of \$452 million (2008 – \$237 million) related to oil sands projects currently in the pre-production stage and undeveloped land acquisition costs of \$12.3 million (2008 – \$15.8 million) were excluded from the depletion calculation.

Included in year-to-date DD&A is an accretion charge of \$1.6 million (2008 – \$1.3 million) in respect of the company's estimated asset retirement obligations. These charges will continue in future years in order to accrete the currently booked discounted liability of \$32.4 million to the estimated total undiscounted liability of \$65.1 million over the remaining economic life of the company's oil sands, crude oil and natural gas properties.

At September 30, 2009, the recoverable value of the company's productive crude oil, oil sands and natural gas assets and its major development projects significantly exceeded their carrying values and therefore no ceiling test write-down was required.

INCOME TAXES

The income tax recovery of \$166,000 in the first nine months of 2009 includes a current income tax recovery of \$1.8 million, and a future income tax provision of \$1.6 million principally related to U.S. refining operations.

At September 30, 2009 the company had approximately \$276 million of non-capital losses which expire between 2010 and 2028, \$656 million of deductible resource pools and \$30 million of deductible financing costs. The future income tax benefit of these have been recognized at September 30, 2009. Additionally, the company had \$32 million of net capital losses available to reduce capital gains in future. These capital losses have no expiry date and their future income tax benefit has not been recognized, due to uncertainty of their realization at September 30, 2009.

EQUITY INTEREST IN PETROLIFERA PETROLEUM LIMITED (“PETROLIFERA”) AND DILUTION GAINS

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

In the third quarter of 2009, Petrolifera issued 66.5 million Units to raise \$58 million. Each Unit was comprised of one Petrolifera common share and one-half Petrolifera Share Purchase Warrant. Each full Petrolifera Share Purchase Warrant is exercisable to purchase one Petrolifera common share at \$1.20 per common share over a period not exceeding two years from issuance (or put date). Connacher subscribed for 13,556,000 Units. On September 1, 2009, Connacher also exercised its options to purchase an additional 200,000 Petrolifera common shares at \$0.50 per common share. Connacher now holds 26.9 million Petrolifera common shares, representing 22 percent of Petrolifera's issued and outstanding common shares and 6.8 million Petrolifera Share Purchase Warrants. These transactions resulted in a dilution loss of \$2.6 million in the third quarter of 2009.

Connacher accounts for its 22 percent equity investment in Petrolifera under the equity method of accounting. Connacher's share of Petrolifera's earnings in the first nine months of 2009 was a loss of \$1.7 million (nine months ended September 30, 2008 – \$2.2 million earnings). In Q3 2009, Connacher's share of Petrolifera's reported loss was \$2.8 million (Q3 2008 – \$854,000 earnings).

NET EARNINGS

In Q3 2009, the company reported earnings of \$47.8 million (\$0.12 per basic and \$0.11 per diluted share outstanding) compared to earnings of \$12.1 million (\$0.06 per basic and diluted share outstanding) in Q3 2008.

In the first nine months of 2009, the company reported earnings of \$40.9 million (\$0.14 per basic and diluted share outstanding) compared to earnings of \$17 million or \$0.08 per basic and diluted share for the first nine months of 2008.

Fluctuations are explained herein in the review of components of earnings.

SHARES OUTSTANDING

For the first nine months of 2009, the weighted average number of common shares outstanding was 294,463,038 (2008 – 210,663,327) and the weighted average number of diluted shares outstanding, as calculated by the treasury stock method, was 294,869,531 (2008 – 213,286,631).

As at November 10, 2009, the company had the following equity securities issued and outstanding:

- 426,812,143 common shares;
- 22,491,304 share purchase options; and
- 489,292 share units under the non-employee director share awards plan.

Additionally, 20,002,800 common shares were reserved and issuable upon conversion of the Convertible Debentures. Details of the exercise provisions and terms of the outstanding options are noted in the consolidated financial statements, included in this interim report.

LIQUIDITY AND CAPITAL RESOURCES

On June 5, 2009 Connacher issued 191,762,500 common shares from treasury at a price of \$0.90 per common share for gross proceeds of \$172.6 million.

On June 16, 2009 the company issued US\$200 million face value of 11.75 percent First Lien Senior Secured Notes (the “First Lien Senior Notes”) at a price of 93.678 percent for gross proceeds of US\$187.4 million. The First Lien Senior Notes are not repayable until July 15, 2014 and are secured on a first priority basis (subject to specified liens up to US\$50 million for prior ranking senior debt) by liens on all of the company's assets, excluding Connacher's investment holding in Petrolifera.

Proceeds from the equity and First Lien Senior Note financings, net of issuance costs, were approximately \$370 million. These funds were raised for working capital and general corporate purposes, including to fund the remaining costs associated with the construction of Algar, the company's second 10,000 bbl/d SAGD oil sands project and the drilling and completion of the associated SAGD well pairs and to fund other capital expenditures.

At September 30, 2009, the company had working capital of \$347 million, including \$334 million of cash on hand, of which \$10 million was segregated to collateralize letters of credit. As the company's indebtedness is long-term in nature, with no principal debt repayment obligations until June 2012 at the earliest, management believes that the company presently has sufficient liquidity to complete the Algar project, to fund its ongoing capital program and to satisfy its financial obligations.

In October 2009, to fund the company's winter exploration program the company issued an additional 23,172,500 common shares from treasury on a flow-through basis at \$1.30 per share, for gross proceeds of \$30 million.

We are mindful of the need to retain a high level of liquidity and a strong balance sheet while we conduct our extensive construction program at Algar. We recently were successful in securing commitments for a new US\$50 million revolving credit facility from a strong syndicate of Canadian and international banks and are in the process of finalizing the documentation for this facility. It will be a first lien instrument and rank ahead of Connacher's term indebtedness and provides the company with another degree of financial flexibility. Securing this facility is a further indication of the positive light in which the company is held in financial markets. We are also pleased to see the rapid and significant improvement in the market pricing of our outstanding debt instruments, which reflects the improvement in overall industry conditions and Connacher's performance.

The recent financial crisis has severely reduced liquidity in capital and bank markets. Economic uncertainty and significant volatility in commodity markets and stock markets have also occurred around the world. Notwithstanding the challenges imposed by this crisis and current economic conditions, management believes that the company has attractive internally-generated growth prospects which, with our cash balances, the impact of an improvement in commodity prices and our overall financial liquidity will allow us to expand our operations.

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

In order to mitigate foreign exchange exposure to commodity pricing, the company entered into a foreign exchange revenue collar which throughout 2009 sets a floor of CAD\$1.1925 per US\$1.00 and a ceiling of CAD\$1.30 per US\$1.00 on a notional amount of US\$10 million of production revenue per month. Additionally, in 2009 the company entered into WTI derivatives on three tranches of 2,500 bbl/d of notional production with staggered maturities throughout 2009 and 2010 at increasing prices.

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

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

	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
(\$000s)				
Net earnings	\$ 47,767	\$ 12,139	\$ 40,889	\$ 16,989
Items not involving cash:				
Depletion, depreciation and accretion	16,691	14,968	49,678	36,257
Stock-based compensation	623	790	2,444	3,487
Finance charges – non-cash portion	1,438	1,238	3,613	6,545
Employee future benefits	70	117	364	344
Future income tax provision (recovery)	8,438	1,233	1,637	(557)
Unrealized foreign exchange (gain) loss	(53,458)	1,439	(87,074)	6,648
Unrealized gain on risk management contracts	(14,753)	-	1,757	-
Gain on repurchase of Second Lien Senior Notes	(1,796)	-	(2,271)	-
Equity interest in Petrolifera (earnings) loss	2,797	(854)	1,658	(2,244)
Dilution (gain) loss	2,593	60	2,593	(7,964)
Cash flow from operations before changes in non-cash working capital and other changes	\$ 10,410	\$ 31,130	\$ 15,288	\$ 59,505

In Q3 2009, cash flow was \$10 million (\$0.03 per basic and diluted share), 67 percent lower than the \$31 million reported (\$0.15 per basic and \$0.14 per diluted share) for Q3 2008 and in the first nine months of 2009 cash flow was \$15.3 million (\$0.05 per basic and diluted share) compared to cash flow of \$59.5 million (\$0.28 per basic and \$0.27 per diluted share) reported in the first nine months of 2008. The primary reason for lower reported cash flows in 2009 compared to 2008 was lower commodity selling prices for each of our upstream and downstream business segments, as noted herein in the detailed explanations of our business activities.

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

The company's only financial instruments are cash, restricted cash, accounts receivable and payable, amounts due from Petrolifera, the Convertible Debentures, the First and Second Lien Senior Notes and its financial derivative contracts. The company maintains no off-balance sheet financial instruments, other than the foreign exchange revenue collar and the WTI derivatives, referenced above.

As the First and Second Lien Senior Notes are denominated in U.S. dollars, there is a foreign exchange risk associated with their semi-annual interest payments and the repayment of their principal balances in 2014 and 2015, using Canadian currency. The next semi-annual interest payment of US\$43 million is due in December 2009.

Connacher's capital structure is composed of:

	As at September 30, 2009	As at December 31, 2008
(\$000)		
Long term debt ⁽¹⁾	\$ 889,113	\$ 778,732
Shareholders' equity		
Share capital, contributed surplus and equity component	606,990	437,899
Accumulated other comprehensive income (loss)	(12,929)	7,802
Retained earnings	64,275	23,386
Total	\$ 1,547,449	\$ 1,247,819
Debt to book capitalization ⁽²⁾	57%	62%
Debt to market capitalization ⁽³⁾	64%	81%

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

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

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

Connacher currently has a high calculated ratio of debt to capitalization. This is due to pre-funding the full cost of Algar. As at September 30, 2009, the company's net debt (long-term debt, net of cash on hand) was \$555 million, its calculated ratio of net debt to book capitalization was 46 percent and the percentage of its net debt to market capitalization was 53 percent.

FINANCINGS COMPLETED IN 2009

COMMON SHARE ISSUANCE

On June 5, 2009 Connacher issued 191,762,500 common shares from treasury at a price of \$0.90 per common share for net proceeds of \$164 million after fees and expenses. The proceeds were raised for working capital to fund the company's capital expenditures, including Algar, and for general corporate purposes.

To September 30, 2009, the proceeds of the common share issuance have been utilized as follows:

	As stated at the time of financing	As actually applied to date
(\$millions)		
Gross proceeds	\$ 173	\$ 173
Underwriters commissions and issue costs	(9)	(9)
Net proceeds	164	164
Use of proceeds:		
Oil sands capital	\$ 38	\$ 33
Conventional capital	6	2
Refinery capital	16	7
General corporate purposes ⁽¹⁾	104	16
Excess - included in cash	-	106
Total	\$ 164	\$ 164

(1) As proposed at the time of financing, \$104 million was dedicated to general corporate purposes.

FIRST LIEN SENIOR SECURED NOTES

On June 16, 2009, the company issued US\$200 million first lien five-year secured notes ("First Lien Senior Notes") at an issue price of 93.678 percent for net proceeds of \$205 million, after fees and expenses. The proceeds were to be used for working capital and general corporate purposes, including to fund a portion of the remaining construction, drilling and completion costs associated with the construction of Algar.

To September 30, 2009, the proceeds of the First Lien Senior Note financing have been utilized as follows:

(\$millions)	As stated at the time of financing	As actually applied to date
Gross proceeds	\$ 226	\$ 226
Underwriters commissions and issue costs	(21)	(21)
Net proceeds	\$ 205	\$ 205
Use of proceeds:		
Algar construction, drilling and completion costs	\$ 205	\$ 57
Working capital and general corporate purposes ⁽¹⁾	-	148
Total	\$ 205	\$ 205

(1) To the extent funds raised have not been utilized for Algar, they have been added to working capital and are included in company's cash balances maintained at September 30, 2009.

PROPERTY AND EQUIPMENT EXPENDITURES

Property and equipment expenditures totaled \$101 million in Q3 2009 and \$205 million for the year-to-date. A breakdown of these expenditures together with prior year comparatives follows.

(\$000)	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
Oil sands, crude oil and natural gas expenditures	\$ 92,207	\$ 62,259	\$ 189,930	\$ 250,691
Refinery expenditures	8,520	6,916	15,288	14,872
	\$ 100,727	\$ 69,175	\$ 205,218	\$ 265,563

In Q3 2009, oil sands capital expenditures totaled \$90 million; \$57 million of this was incurred on the Algar oil sands project. Additionally, \$6 million of capital costs were incurred at Pod One for the completion of the two additional SAGD well pairs, for costs to install one ESP, the plant turnaround and for other facility enhancement expenditures, and \$27 million was incurred on co-generation facilities, transfer pipeline facilities, for capitalized interest and G&A costs and for asset retirement expenditures. In Q3 2009, \$2 million was also incurred for conventional facility expenditures.

For the year-to-date, expenditures of \$89 million were incurred on the Algar project; \$24 million was incurred at Pod One to drill and complete the two additional SAGD well pairs and to install five ESPs, the plant turnaround and for other facility enhancement expenditures and \$69 million was incurred on drilling 23 exploratory core holes, for co-generation and pipeline facilities, for capitalized interest and for G&A costs. For the year-to-date, \$8 million was also incurred on conventional drilling (two wells), land acquisitions, seismic, well workovers and facilities.

Refinery capital expenditures in Q3 2009 and for the year-to-date for 2009 were primarily directed to the completion and tie-in of our new hydrogen plant to complete the ultra-low sulphur diesel project and related to the turnaround and scheduled replacement of the fluid cat cracker reactor.

Oil sands, crude oil and natural gas capital expenditures of \$62 million in Q3 2008 were comprised of preliminary facility expenditures and costs incurred for long lead-order equipment items for the Algar project, for truck loading facilities at Pod One, core hole and conventional drilling costs and for capitalized interest and G&A costs.

For the 2008 year-to-date, oil sands and conventional exploration expenditures totaled \$74 million; Algar facility and equipment expenditures totaled \$82 million; conventional natural gas facilities totaled \$19 million; Pod One turnaround costs, a horizontal well re-drill, truck loading facilities and capitalized pre-operating costs totaled \$25 million; and capitalized interest, G&A and other expenditures totaled \$51 million.

Most of the 2008 capital expenditures at our refinery were incurred on the ultra low sulphur diesel conversion project.

OUTLOOK

We anticipate that the current general economic conditions and product price volatility will continue to challenge industry profitability and growth. However, recent oil price improvements and the prospect for some pricing stability have provided a basis for some investment optimism. Together with the optimization of some of our operational and marketing processes, moderately higher oil prices have contributed to improved operating and financial conditions.

We anticipate continued profitability from our upstream business unit, primarily due to improved production and sales volumes. Refining industry margins remain challenged with narrow light/heavy oil pricing differentials and lower refined product demands. However, our refinery has contributed positive results in 2009, largely because of strong asphalt demand. Operating in a "niche" market also provides some insulation from volatile refined product margins experienced in coastal areas of the U.S., where refiners compete against imported products from Europe and Asia.

Our recently completed financings have added significant financial liquidity. Upon the completion of the equity and First Lien Senior Note financings, Connacher's Board of Directors sanctioned the resumption of construction of Algar (which was suspended in December 2008). To the end of September

2009, approximately \$219 million has been invested in Algar. The majority of the long-lead equipment items have been built as were three well pads and the road to the plant site. Since resuming construction at Algar in July 2009, we have had the benefit of good weather, good contractors and good drillers and note that we are presently on schedule and on budget to complete this project in April 2010. We then plan to commission the plant in May and steam the wells from June to August, before converting the wells to production mode. Algar is expected to begin contributing to operating results in late 2010 and ramp-up to near design capacity in late 2010 or early 2011.

The total cost of Algar, excluding capitalized items and contingencies, is currently estimated to be \$360 million. Savings arising from remaining activities occurring in a more "normalized" construction and labour environment have been offset by minor scope changes to the project and to ensure effective exploitation of the reservoir and the decision to drill and complete two additional SAGD well pairs at Algar, bringing to 17 the total SAGD well pairs.

In addition, to recognize unplanned events that often occur during a major construction project and to factor in unpredictable and often severe winter weather that can occur in northern Alberta, a \$15 million contingency has been provided to the Algar budget, bringing the total cost for Algar, excluding capitalized items, to \$375 million, of which \$128 million was incurred prior to 2009, \$161 million is estimated to be incurred in 2009 and the \$86 million balance is forecast to be incurred in 2010.

In the fourth quarter of 2009, the company anticipates spending approximately \$71 million on the Algar project, \$6 million at the refinery, primarily to complete the plant turnaround and the reactor unit replacement project, \$13 million on capitalized interest and G&A, \$8 million on co-generation and sales transfer lines and \$3 million on conventional activities.

The company's business plan anticipates continued long-term growth with continued increases in revenue and cash flow from our oilsands projects, conventional crude oil and natural gas production and from stable refining operations.

The company's 2010 capital budget has been set at \$274 million, broken out as follows:

(\$millions)		
Complete Algar	\$	86
Algar capitalized interest, G&A and pre-commercial operations		57
Algar ESP pre-work and facility optimization		8
Cogeneration and sales transfer lines		18
Pod One, including two new SAGD wells, 11 high temperature ESPs and facility optimization		30
EIA application		2
Expand Pod One trucking terminal		5
Exploration program		33
Conventional and head office capital		16
Refinery, including benzene removal project and steam boiler replacement		19
	\$	274

The company anticipates that cash balances and cash flow generated in 2009 and 2010 will be more than sufficient to fund all related 2009 and 2010 capital and contractual debt servicing obligations.

In June 2009, we provided a financial outlook in our corporate presentation and in the confidential offering circular that was issued to the First Lien Senior Note investors, which contained an estimate of the 2010 Pod One bitumen netback and 2010 Pod One full cycle operating margin. This financial outlook represented our then current estimates of revenue, operating and other costs, per barrel of bitumen sold, assuming that Pod One achieved targeted 2010 production levels of 9,490 bbl/d. No incremental production was included in the financial outlook in respect of our Algar project. This financial outlook was intended to provide investors with a measure of the ability of our Pod One project (which achieved commerciality in March 2008) and integrated business model to generate positive netbacks assuming full production. Pod One netbacks and corporate netbacks generated prior to full production are anticipated to be lower than the estimates contained in the financial outlook due to production ramp-up and initially higher operating costs.

In connection with the development of our 2010 budget, we have updated our financial outlook to incorporate current expectations with respect to future commodity and feedstock prices, light/heavy differentials, royalty rates and foreign exchange rates. In addition, we have utilized our current operating experience and production history to update our outlook with respect to future production levels, transportation and operating costs and refinery throughput. We have also included estimated incremental production for our Algar project which is presently under construction and anticipated to achieve commerciality on or about October 1, 2010. Our planned 2010 capital budget is \$274 million. This capital budget includes maintenance and replacement capital, in addition to capital requirements for production growth and regulatory compliance. The updated financial outlook provided below is prior to all capital expenditures, including maintenance and replacement capital. As a result, we will not be providing an estimate of full cycle operating margin as contained in our prior guidance. The updated financial outlook is as at November 11, 2009 and replaces our prior financial outlook. This outlook will be reviewed on a quarterly basis and may be revised as required.

The calculations of netback and adjusted earnings before interest, taxes, depreciation and amortization ("EBITDA") are non-GAAP measures. The closest GAAP measure to the netback calculations and adjusted EBITDA calculation is net earnings. The updated 2010 financial outlook will be reconciled to net earnings in the applicable MD&A on a quarterly and annual basis in 2010.

Actual netbacks and adjusted EBITDA achieved during 2010 could differ materially from the estimates contained in our financial outlook. The material risk factors that we have identified toward achieving these future netbacks and adjusted EBITDA are outlined in the Risk Factors and Forward Looking Information sections of our Annual Information Form for the year ended December 31, 2008 ("AIF"). In particular, we may experience difficulties or interruptions and additional costs during the production of bitumen,

crude oil and natural gas; we may encounter timing difficulties or delays and additional costs relating to the construction of the Algar project; we may experience difficulties in delivering diluent to our oil sands projects and dilbit to commercial markets; the performance and availability of facilities owned by third parties may adversely affect our operations; crude oil and natural gas prices may fluctuate from current estimates; there may be changes in refining spreads to WTI and changes in the differential pricing between heavy and light crude oil prices; there may be adverse currency fluctuations; general economic conditions may remain volatile thus affecting demand for our products and/or the costs for labour, equipment and services and changes in, or the introduction of new, government regulations relating to our business may increase operating costs.

The following tables represent our current estimate of revenue, operating and other costs, per barrel of bitumen sold, assuming Pod One and Algar achieve targeted best estimate 2010 production levels, which by assumption infers there is an equal probability production levels will be greater or less than the targeted volumes. The information presented below is based on our current estimate of crude oil prices, foreign exchanges rates, heavy oil differentials, dilbit quality discounts, diluent premium to WTI, diluent and dilbit transportation costs, dilbit blending ratios and other costs and are calculated on an annualized basis and may not reflect actual quarterly netbacks or adjusted EBITDA. Volatility in quarterly netbacks and adjusted EBITDA will occur due to, among other things, seasonality factors affecting our operations. The key assumptions relating to the financial outlook are set out in the notes following the tables below.

ESTIMATED 2010 BITUMEN NETBACK ⁽¹⁾

Constant US\$75 WTI	
\$/bbl of bitumen	
Bitumen price at wellhead ^(2,3)	\$ 47.27
Financial derivative gain ⁽⁴⁾	0.74
Royalties ⁽⁵⁾	(1.66)
Operating costs	
Natural gas ⁽⁶⁾	(5.86)
Other operating costs ⁽⁷⁾	(7.65)
Bitumen netback	\$ 32.84

(1) Assumes estimated total average daily bitumen production of 10,685 bbl/d in 2010; 9,000 bbl/d from Pod One and 1,685 bbl/d from Algar and has not been adjusted for inflation. See "Forward Looking Information" and "Risk Factors" sections of our AIF. Production from Algar assumes commerciality is declared effective October 1, 2010 and has been annualized for calendar 2010. Pod One production estimates for 2010 incorporate higher downtime due to planned events arising from the anticipated installation of 11 high temperature ESPs and the tie-in of two additional SAGD well pairs during 2010 and the annual turnaround at the Pod One plant, plus builds in higher downtime for events and factors outside of our control such as weather related interruptions, power outages and other unplanned events that can and do occur in the operation of a SAGD facility and associated well pairs.

(2) Based on constant WTI price of US\$75.00/bbl, a light/heavy differential of US\$12.00/bbl and a quality charge of \$5.00/bbl, resulting in a dilbit price of \$61.15/bbl. Also assumes a foreign exchange rate of \$1.05 = US\$1.00.

(3) The bitumen price at the wellhead is net of dilbit transportation costs of \$6.00/bbl and a diluent blending cost of \$27.92/bbl, including \$1.67/bbl of diluent transportation costs, a zero diluent premium to WTI and a blending ratio of 25 percent for Pod One and a diluent blending cost of \$35.89/bbl, including \$2.14/bbl of diluent transportation costs, a zero diluent premium to WTI and a blending ratio of 30 percent for Algar.

(4) Benefit from a US\$78.00/bbl WTI swap on 2,500 bbl/d of bitumen production for calendar 2010.

(5) Royalties are calculated on a pre-payout basis and are estimated to be \$1.68/bbl for Pod One and \$1.57/bbl for Algar.

(6) Based on an average SOR of 3.0 for Pod One and 3.4 for Algar and a natural gas price of US\$4.76/Mcf which equates to \$5.86/bbl or approximately 12,550 Mcf/d of natural gas burned to produce 10,685 bbl/d of bitumen. The SORs for Pod One are a conservative estimate reflecting the impact of higher SORs experienced to date in the five north wells of Pod 101 and the impact of steaming the two new SAGD well pairs planned in 2010. The SORs from Algar reflect the relative infancy of the SAGD well pairs and are expected to trend down as the wells are optimized and as ESPs are added.

(7) Assumes \$7.20/bbl of other operating costs for Pod One and \$10.07/bbl of other operating costs at Algar.

ESTIMATED 2010 ADJUSTED EBITDA ^(1,2)

Constant US\$75 WTI	
\$/bbl of bitumen	
Corporate netback contribution	
Bitumen netback ⁽³⁾	\$ 32.84
Conventional netback ⁽⁴⁾	4.15
Refinery netback ⁽⁵⁾	4.65
Corporate netback	41.64
Corporate G&A ⁽⁶⁾	(4.39)
Adjusted EBITDA	\$ 37.25

(1) Assumes estimated total average daily bitumen production of 10,685 bbl/d in 2010; 9,000 bbl/d from Pod One and 1,685 bbl/d from Algar and has not been adjusted for inflation. Also assumes a foreign exchange rate of \$1.05 = US\$1.00.

(2) See "Forward Looking Information" and "Risk Factors" sections in our AIF.

(3) See the table above for assumptions.

(4) Represents a blended conventional oil and natural gas netback per barrel of bitumen. Assumes estimated production of 905 bbl/d of conventional crude oil and 8,909 Mcf/d of natural gas production. Conventional oil assets anticipated revenue based on average realized oil price of US\$59.81/bbl and natural gas assets revenue based on average realized natural gas price of US\$4.76/Mcf. Conventional asset netback is based on 26 percent average royalty rate and average operating costs of \$12.69/boe.

(5) Assumes estimated refinery production of 10,345 bbl/d, feedstock purchased at US\$66.14/bbl, refined products sold with a spread to WTI of US\$3.71/bbl and operating costs of US\$8.00/bbl, implying a refining margin of US\$4.57/bbl of throughput.

(6) Excludes capitalized G&A of \$1.15/bbl.

Information relating to Connacher, including Connacher's Annual Information Form is on SEDAR at www.sedar.com. See also the company's website at www.connacheroil.com.

NEW SIGNIFICANT ACCOUNTING POLICIES

In February 2008, the CICA issued Section 3064, "Goodwill and Intangible Assets", replacing Section 3062, "Goodwill and Other Intangible Assets." The new Section became applicable in 2009 and the company adopted the new standard effective January 1, 2009. Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062, and did not cause any change to the company's financial statements.

In January 2009, the CICA Emerging Issues Committee ("EIC") issued EIC-173, "Credit risk and the fair value of financial assets and liabilities", which requires that an entity's own credit risk and counterparty credit risk be taken into account in determining the fair value of financial assets and liabilities, including derivative financial instruments. The provisions of EIC-173 apply to all financial assets and liabilities measured at fair value in interim and annual financial statements for periods ending on or after January 20, 2009. The adoption of this standard had no material impact on the company's financial statements.

In June 2009, the CICA issued amendments to CICA Handbook Section 3862, Financial Instruments – Disclosures. The amendments include enhanced disclosures related to the fair value of financial instruments and the liquidity risk associated with financial instruments. The amendments will be effective for annual financial statements for fiscal years ending after September 30, 2009 and are consistent with recent amendments to financial instrument disclosure standards in IFRS. The company will include these additional disclosures in its annual consolidated financial statements for the year ending December 31, 2009.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In 2008, the Canadian Accounting Standards Board confirmed that publicly accountable enterprises will be required to adopt International Financial Reporting Standards ("IFRS") in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011.

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

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

In July 2009 the International Accounting Standards Board ("IASB") issued an amendment to IFRS accounting standards in respect of property, plant and equipment as at the date of the initial transition to IFRS which permits issuers currently using the full cost method of accounting, (as described in the CICA Handbook – Accounting Guideline 16 Oil and Gas accounting – Full Cost), to allocate the balance of property, plant and equipment as determined under Canadian GAAP to the IFRS categories of exploration and evaluation assets and development and producing properties without requiring full retroactive restatement of historic balances to the IFRS basis of accounting. We anticipate using the exemption.

RISK FACTORS AND RISK MANAGEMENT

Connacher is engaged in the oil and gas exploration, development, production and refining industry. This business is inherently risky and there is no assurance that hydrocarbon reserves will be discovered and economically produced. Operational risks include competition, reservoir performance uncertainties, environmental factors and regulatory and safety concerns. Financial risks associated with the petroleum industry include fluctuations in commodity prices, interest rates, currency exchange rates and the cost of goods and services.

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

Reference should be made to Connacher's most recent Annual Information Form for a description of its risk factors. The company's Annual Information Form is available on SEDAR at www.sedar.com.

DISCLOSURE CONTROLS AND PROCEDURES

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

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the company's financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP.

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

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

QUARTERLY RESULTS

Fluctuations in results over the previous eight quarters are due principally to variations in oil and gas prices, production/sales volumes and foreign exchange rates relative to U.S. dollar denominated debt. Significant volatility and declining commodity prices, together with severe economic uncertainty in the fourth quarter of 2008 and the first quarter of 2009 are the primary factors affecting financial results during those quarters. The magnitude of the changes in commodity prices during these periods was unprecedented.

Three Months Ended	2007	2008	2008	2008	2008	2009	2009	2009
	Dec 31	Mar 31	Jun 30	Sept 30	Dec 31	Mar 31	June 30	Sept 30
(\$'000 except per share amounts)								
Revenues, net of royalties	83,340	100,656	202,016	224,558	102,109	61,757	100,219	151,360
Cash flow ⁽¹⁾	7,083	7,825	20,550	31,130	(4,688)	(4,692)	9,570	10,410
Basic, per share ⁽¹⁾	0.03	0.04	0.10	0.15	(0.02)	(0.02)	0.04	0.03
Diluted, per share ⁽¹⁾	0.03	0.03	0.10	0.14	(0.02)	(0.02)	0.03	0.03
Net earnings (loss)	(840)	(1,833)	6,683	12,139	(43,592)	(46,844)	39,966	47,767
Basic per share	0.00	(0.01)	0.03	0.06	(0.21)	(0.22)	0.15	0.12
Diluted per share	-	-	-	-	-	-	0.14	0.11
Property and equipment additions	55,852	115,984	80,403	69,175	86,174	64,255	40,236	100,727
Cash on hand	392,271	323,423	232,704	236,375	223,663	96,220	401,160	333,634
Working capital surplus	389,789	287,105	234,110	200,177	197,914	120,035	455,001	347,139
Term debt	664,462	671,014	684,705	689,673	778,732	803,915	960,593	889,113
Shareholders' equity	480,439	471,559	479,477	496,509	469,087	428,276	622,235	658,336
Operating Highlights								
Upstream: Daily production/sales volumes								
Bitumen – bbl/d ⁽²⁾	-	1,773	6,123	6,810	7,086	6,170	6,284	6,551
Crude oil – bbl/d	752	996	981	957	1,187	1,180	1,114	993
Natural gas – Mcf/d	8,889	10,493	14,220	13,188	12,405	12,828	12,144	10,377
Equivalent – boe/d ⁽³⁾	2,233	4,518	9,474	9,966	10,341	9,488	9,421	9,274
Product pricing ⁽⁴⁾								
Bitumen – \$/bbl ⁽²⁾	-	53.01	60.80	65.34	12.06	22.45	40.95	45.30
Crude oil – \$/bbl	56.79	79.50	105.28	103.60	48.13	39.63	54.87	60.58
Natural gas – \$/Mcf	5.82	7.79	10.02	8.92	6.61	4.89	3.35	2.91
Selected Highlights – \$/boe ⁽³⁾								
Weighted average sales price	42.29	56.44	65.25	66.41	21.73	26.13	38.11	41.74
Realized derivative gain (loss)	-	-	(0.47)	-	-	0.47	(7.19)	(9.74)
Royalties	6.34	7.45	6.21	4.65	3.19	3.02	1.90	2.13
Operating costs	13.77	14.32	22.78	20.41	20.76	17.73	13.98	15.43
Cash operating netback ⁽⁵⁾	22.18	34.67	35.79	41.35	(2.23)	5.85	15.04	14.44
Downstream: Refining								
Crude charged – bbl/d	9,610	9,830	9,329	9,239	8,333	6,867	9,145	7,076
Refining utilization – %	101	104	98	97	88	72	96	75
Margins – %	6	1	(0.1)	2	(18)	7	5	8
Common Share Information								
Shares outstanding end of period (000)	209,971	210,277	211,027	211,182	211,182	211,291	403,546	403,567
Weighted average shares outstanding for the period								
Basic (000)	204,701	210,234	210,658	211,093	211,182	211,286	266,425	403,565
Diluted (000)	220,362	210,234	214,530	213,174	211,575	211,286	286,985	424,058
Volume traded (000)	52,198	63,718	107,001	112,401	110,244	67,387	249,700	129,206
Common share price (\$)								
High	4.08	3.94	5.26	4.65	2.95	1.00	1.66	1.15
Low	3.31	2.59	3.10	2.63	0.60	0.61	0.74	0.76
Close (end of period)	3.79	3.13	4.30	2.75	0.74	0.74	0.92	1.10

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

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

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

(4) Product pricing excludes realized hedging gains/losses and excludes unrealized mark-to-market non-cash accounting gains/losses.

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

CONSOLIDATED BALANCE SHEETS

(UNAUDITED)

(\$000)	September 30, 2009	December 31, 2008
ASSETS		
CURRENT		
Cash	\$ 323,634	\$ 223,663
Restricted cash (Note 9(c))	10,000	-
Accounts receivable	42,265	20,492
Inventories (Note 5)	33,094	35,993
Income taxes recoverable	15,526	13,875
Prepaid expenses	18,810	2,221
Risk management contract (Note 4(b))	3,431	-
Due from Petrolifera	48	42
	446,808	296,286
Property and equipment	1,131,205	985,054
Goodwill	103,676	103,676
Investment in Petrolifera (Note 9(d))	54,437	46,659
	\$ 1,736,126	\$ 1,431,675
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	\$ 97,912	\$ 98,372
Risk management contracts (Note 4(b))	1,757	-
	99,669	98,372
Long term debt (Note 4(e))	889,113	778,732
Future income taxes	55,851	58,296
Asset retirement obligations (Note 6)	32,355	26,396
Employee future benefits	802	792
	1,077,790	962,588
SHAREHOLDERS' EQUITY		
Share capital, contributed surplus and equity component (Note 7)	606,990	437,899
Retained earnings	64,275	23,386
Accumulated other comprehensive income (loss)	(12,929)	7,802
	658,336	469,087
	\$ 1,736,126	\$ 1,431,675

CONSOLIDATED STATEMENTS OF OPERATIONS AND RETAINED EARNINGS

(UNAUDITED)

(\$000, except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
REVENUES				
Upstream, net of royalties (Note 4(b))	\$ 58,709	\$ 96,291	\$ 120,737	\$ 207,700
Downstream	90,462	127,726	189,236	317,445
Interest and other income	2,189	541	3,363	2,085
	151,360	224,558	313,336	527,230
EXPENSES				
Upstream – diluent purchases and operating costs	26,230	52,125	77,920	117,026
Upstream transportation costs	3,155	6,256	8,637	9,684
Downstream – crude oil purchases and operating costs (Note 5)	85,015	125,455	181,346	314,774
General and administrative	3,364	2,774	11,062	8,751
Finance charges	13,127	7,786	31,164	22,515
Stock-based compensation (Note 7(b))	623	790	2,444	3,487
Foreign exchange loss (gain) (Note 4(d))	(56,344)	1,439	(93,889)	6,648
Depletion, depreciation and accretion	16,691	14,968	49,678	36,257
	91,861	211,593	268,362	519,142
Earnings before income taxes and other items	59,499	12,965	44,974	8,088
Current income tax provision (recovery)	(2,096)	387	(1,803)	1,864
Future income tax provision (recovery)	8,438	1,233	1,637	(557)
	6,342	1,620	(166)	1,307
Earnings before other items	53,157	11,345	45,140	6,781
Equity interest in Petrolifera earnings (loss)	(2,797)	854	(1,658)	2,244
Dilution gain (loss) (Note 9(d))	(2,593)	(60)	(2,593)	7,964
NET EARNINGS	47,767	12,139	40,889	16,989
RETAINED EARNINGS, BEGINNING OF PERIOD	16,508	54,839	23,386	49,989
RETAINED EARNINGS, END OF PERIOD	\$ 64,275	\$ 66,978	\$ 64,275	\$ 66,978
EARNINGS PER SHARE (Note 9(a))				
Basic	\$ 0.12	\$ 0.06	\$ 0.14	\$ 0.08
Diluted	\$ 0.11	\$ 0.06	\$ 0.14	\$ 0.08

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(UNAUDITED)

(\$000)	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
Net earnings	\$ 47,767	\$ 12,139	\$ 40,889	\$ 16,989
Foreign currency translation adjustment	(12,163)	4,025	(20,731)	7,105
Comprehensive income	\$ 35,604	\$ 16,164	\$ 20,158	\$ 24,094

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

(UNAUDITED)

(\$000)	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
Balance, beginning of period	\$ (766)	\$ (10,556)	\$ 7,802	\$ (13,636)
Foreign currency translation adjustment	(12,163)	4,025	(20,731)	7,105
Balance, end of period	\$ (12,929)	\$ (6,531)	\$ (12,929)	\$ (6,531)

CONSOLIDATED STATEMENTS OF CASH FLOW

(UNAUDITED)

(\$000)	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
Cash provided by (used in) the following activities:				
OPERATING				
Net earnings	\$ 47,767	\$ 12,139	\$ 40,889	\$ 16,989
Items not involving cash:				
Depletion, depreciation and accretion	16,691	14,968	49,678	36,257
Stock-based compensation	623	790	2,444	3,487
Finance charges – non cash portion	1,438	1,238	3,613	6,545
Employee future benefits	70	117	364	344
Future income tax provision (recovery)	8,438	1,233	1,637	(557)
Unrealized gain on risk management contracts	(14,753)	-	1,757	-
Unrealized foreign exchange loss (gain)	(53,458)	1,439	(87,074)	6,648
Gain on repurchase of Second Lien Senior Notes	(1,796)	-	(2,271)	-
Equity interest in Petrolifera (earnings) loss	2,797	(854)	1,658	(2,244)
Dilution (gain) loss (Note 9(d))	2,593	60	2,593	(7,964)
Cash flow from operations before changes in non-cash working capital and other changes	10,410	31,130	15,288	59,505
Changes in non-cash working capital (Note 9(b))	25,074	(114)	(25,594)	8,793
Asset retirement expenditures	(23)	(3)	(156)	(209)
Pension funding	-	-	(234)	-
	35,461	31,013	(10,696)	18,089
FINANCING				
Issue of common shares (Note 7(a))	-	-	172,586	-
Share issue costs	(145)	-	(8,930)	-
Exercise of stock options (Note 7)	12	69	172	761
Issuance of First Lien Senior Notes	-	-	226,475	-
Debt issue costs	(260)	-	(21,118)	-
Repurchase of Second Lien Senior Notes	(2,592)	-	(2,901)	-
Deferred financing costs	-	-	-	(77)
	(2,985)	69	366,284	684
INVESTING				
Acquisition and development of oil and gas properties	(95,560)	(68,517)	(198,324)	(255,711)
Acquisition of Petrolifera units (Note 9(d))	(12,029)	-	(12,029)	-
Decrease (increase) in restricted cash	-	(1,616)	(10,000)	29,157
Change in non-cash working capital (Note 9(b))	25,559	37,708	(23,964)	24,859
	(82,030)	(32,425)	(244,317)	(201,695)
NET INCREASE (DECREASE) IN CASH	(49,554)	(1,343)	111,271	(132,922)
Foreign exchange gains (losses) on U.S. dollar cash balances held	(17,972)	3,398	(11,300)	6,183
CASH, BEGINNING OF PERIOD	391,160	200,316	223,663	329,110
CASH, END OF PERIOD	\$ 323,634	\$ 202,371	\$ 323,634	\$ 202,371

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

1. FINANCIAL STATEMENT PRESENTATION

The Consolidated Financial Statements include the accounts of Connacher Oil and Gas Limited and its subsidiaries (collectively "Connacher" or the "company") and are presented in accordance with Canadian generally accepted accounting principles. Operating in Canada, and in the U.S. through its subsidiary, Montana Refining Company, Inc. ("MRCI"), the company is in the business of exploring, developing, producing, refining and marketing crude oil, bitumen and natural gas.

2. SIGNIFICANT ACCOUNTING POLICIES

The interim Consolidated Financial Statements have been prepared following the same accounting policies and methods of computation as indicated in the annual audited Consolidated Financial Statements for the year ended December 31, 2008, except as described in Note 3. The disclosures provided below do not conform in all respects to those included with the annual audited Consolidated Financial Statements. The interim Consolidated Financial Statements should be read in conjunction with the annual audited Consolidated Financial Statements and the notes thereto for the year ended December 31, 2008.

3. NEW ACCOUNTING STANDARDS

In February 2008, the Canadian Institute of Chartered Accountants ("CICA") issued Section 3064, "Goodwill and Intangible Assets", replacing Section 3062, "Goodwill and Other Intangible Assets". The new Section has been applied since January 1, 2009. Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062 and, therefore, did not have any impact on the company's Consolidated Financial Statements.

In January 2009, the CICA Emerging Issues Committee ("EIC") issued EIC-173, "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities", which requires that an entity's own credit risk and counterparty credit risk be taken into account in determining the fair value of financial assets and liabilities, including derivative financial instruments. The provisions of EIC-173 apply to all financial assets and liabilities measured at fair value in interim and annual financial statements for periods ending on or after January 20, 2009. The adoption of this standard had no material impact on the company's Consolidated Financial Statements.

In June 2009, the CICA issued amendments to CICA Handbook Section 3862, Financial Instruments – Disclosures. The amendments include enhanced disclosures related to the fair value of financial instruments and the liquidity risk associated with financial instruments. The amendments will be effective for annual financial statements for fiscal years ending after September 30, 2009 and are consistent with recent amendments to financial instrument disclosure standards in IFRS. The company will include these additional disclosures in its annual audited Consolidated Financial Statements for the year ending December 31, 2009.

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

4. FINANCIAL INSTRUMENTS AND CAPITAL RISK MANAGEMENT

FINANCIAL INSTRUMENTS

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

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

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

CAPITAL RISK MANAGEMENT

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

The company is also exposed to risks in the way it finances its capital requirements. The company manages these financial and capital structure risks by operating in a manner that minimizes its exposures to volatility of the company's financial performance. These risks affecting the company are discussed below.

(a) Credit risk

Credit risk is the risk that a contracting entity will not fulfill its obligations under a financial instrument and cause a financial loss to the company. To help manage this risk, the company has a policy for establishing credit limits, requiring collateral before extending credit to customers where appropriate and monitoring outstanding accounts receivable. The company's financial assets subject to credit risk arise from the sale of crude oil, bitumen, natural gas and refined products to a number of large integrated oil companies and product retailers and are subject to normal industry credit risks. The fair value of

accounts receivable and accounts payable closely approximates their carrying values due to the relatively short periods to maturity of these instruments. The maximum exposure to credit risk is represented by the carrying amount on the consolidated balance sheet. The company regularly assesses its financial assets for impairment losses.

The majority of the company's upstream revenues are composed of bitumen sales. Bitumen sales made to two customers represented 53 percent and 30 percent of bitumen sales in the first nine months of 2009.

(b) Market risk

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

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

Risk Management Contracts

In November 2008, Connacher entered into a foreign exchange revenue collar which sets a floor of CAD\$1.1925 per US\$1.00 and a ceiling of CAD\$1.30 per US\$1.00 on a notional amount of US\$10 million of production revenue per month throughout 2009. At September 30, 2009 the fair value of this contract was an asset of \$3.4 million, as reported on the consolidated balance sheet. For the year-to-date, an unrealized foreign exchange gain of \$1.6 million and a realized foreign exchange gain of \$3.9 million was included in the net foreign exchange gain on the consolidated statement of operations in respect of this contract. A \$0.01 change on the USD/CAD exchange rate would result in a \$360,000 change in the fair value of the revenue collar.

Connacher has entered into derivative contracts to fix the WTI crude oil price on a portion of its production at a price of US\$49.50/bbl on a notional volume of 2,500 bbl/d until December 31, 2009, a WTI crude oil "collar" contract on a notional volume of 2,500 bbl/d of bitumen production from September 1 to December 31, 2009 with a floor of US\$60.00/bbl and a ceiling of US\$84.00/bbl and a derivative contract to fix the WTI crude oil price on a notional 2,500 bbl/d at US\$ 78.00 for calendar year 2010. At September 30, 2009 the fair value of these derivative contracts was a liability of \$1.8 million and a \$15.8 million loss was recorded in upstream revenue on the consolidated statement of operations for the year-to-date. A US\$1.00 change in WTI would result in a \$1.3 million change in the value of the derivatives, resulting in a similar impact on earnings.

(c) Interest rate risk

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

(d) Currency risk

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

As Connacher incurs the majority of its expenditures in Canadian dollars, it is exposed to the impact of fluctuations in the U.S./Canadian dollar exchange rate on pricing of its sales of crude oil and bitumen (which are generally priced by reference to U.S. dollars but settled in Canadian dollars) and for the translation of its U.S. refining operating results, its U.S. dollar cash holdings and its U.S. dollar denominated First and Second Lien Senior Notes to Canadian dollars for financial statement reporting purposes.

In 2009, Connacher had unrealized foreign exchange translation gains of \$53.5 million in the third quarter and \$87.1 million for the year-to-date and realized foreign exchange gains of \$2.8 million in the third quarter and \$6.8 million in the year-to-date, 2009, from the foreign exchange revenue collar and upon the settlement of U.S. dollar denominated obligations.

Throughout most of 2008, Connacher had a cross-currency swap in place to hedge one-half of the foreign exchange exposure on its U.S. dollar debt. This insulated the company from some foreign currency volatility and reduced the impact of a weaker Canadian dollar, which resulted in the unrealized foreign exchange translation losses reported in the comparative 2008 periods.

Relative to the company's U.S. dollar cash balances, its crude oil and bitumen revenue receivables and its First and Second Lien Senior Notes, a \$0.01 change in the Canadian dollar exchange rate would have resulted in a change in net earnings of \$4.9 million for the nine months ended September 30, 2009 (nine months ended September 30, 2008 – \$1 million) and would have changed Other Comprehensive Income by \$200,000.

(e) Liquidity risk

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

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

On June 16, 2009, the company issued US\$200 million face value of 11.75 percent First Lien Senior Secured Notes (the "First Lien Senior Notes") at a price of 93.678 percent, for gross proceeds of US\$187.4 million. The First Lien Senior Notes are not repayable until July 15, 2014 and are secured on a first priority basis (subject to specified liens up to US\$50 million for prior ranking senior debt) by liens on all of the company's assets, excluding Connacher's investment holding in Petrolifera, pipeline assets of a dormant subsidiary and cash used to support Connacher's cash collateralized L/C facility.

The long-term nature of the company's debt repayment obligations is structured to be aligned to the long-term nature of its assets. The Convertible Debentures do not mature until June 30, 2012, unless earlier converted to common shares and principal repayments are not required on the First Lien Senior Notes until their maturity date of July 15, 2014 and on the Second Lien Senior Notes until their maturity date of December 15, 2015. This affords Connacher the opportunity to deploy its conventional, oil sands and refining cash flow to fund growth expenditures over the next several years, without having to make principal payments or raise new capital, unless expenditures exceed cash flow and credit capacity.

At September 30, 2009, the fair values of the Convertible Debentures, the First Lien Senior Notes and Second Lien Senior Notes were \$77 million, \$227 million and \$509 million, respectively, based on their quoted market prices.

As at September 30, 2009, the company's long-term debt was repayable as follows:

- Convertible Debentures – June 30, 2012 in the amount of \$100,014,000, unless converted into common shares prior thereto;
- First Lien Senior Notes – July 15, 2014 in the amount of US\$200 million; and
- Second Lien Senior Notes – December 15, 2015 in the amount of US\$587.4 million.

Connacher owns 26.9 million common shares and 6.8 million Share Purchase Warrants of Petrolifera. These each trade on the TSX, and, subject to certain limitations, potentially provide additional liquidity as they have not been collateralized. Although it is not Connacher's intention to sell its investment in Petrolifera in the foreseeable future, this shareholding provides Connacher a margin of financial flexibility.

(f) Capital risks

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

The company manages its capital structure and follows a financial strategy that considers economic and industry conditions, the risk characteristics of its underlying assets and its growth opportunities. It strives to continuously improve its credit rating and reduce its cost of capital. Connacher monitors its capital using a number of financial ratios and industry metrics to ensure its objectives are being met. Connacher's long-term debt contains no financial or maintenance covenants.

In March 2009, the company cancelled its Revolving Credit Facility and put in place a \$20 million demand operating banking facility ("the L/C Facility") for the purposes of issuing letters of credit. The L/C Facility is currently secured by cash of \$10 million and a first lien claim on certain assets of the company and contains no financial or maintenance covenants. At September 30, 2009, the L/C Facility secured letters of credit in the amount of \$7.5 million.

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

	As at September 30, 2009	As at December 31, 2008
(\$000)		
Long term debt ⁽¹⁾	\$ 889,113	\$ 778,732
Shareholders' equity		
Share capital, contributed surplus and equity component	606,990	437,899
Accumulated other comprehensive income (loss)	(12,929)	7,802
Retained earnings	64,275	23,386
Total	\$ 1,547,449	\$ 1,247,819
Debt to book capitalization ⁽²⁾	57%	62%
Debt to market capitalization ⁽³⁾	64%	81%

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

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

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

Connacher currently has a high calculated ratio of debt to capitalization. This is due to pre-funding the full cost of Algar. As at September 30, 2009, the company's net debt (long-term debt, net of cash on hand) was \$555 million, its calculated ratio of net debt to book capitalization was 46 percent and its net debt to market capitalization was 53 percent.

5. INVENTORIES

Inventories consist of the following:

(\$000)	September 30, 2009	December 31, 2008
Crude oil	\$ 6,919	\$ 3,433
Other raw materials and unfinished products ⁽¹⁾	880	1,762
Refined products ⁽²⁾	20,073	18,901
Process chemicals ⁽³⁾	1,712	8,110
Repair and maintenance supplies and other ⁽⁴⁾	3,510	3,787
	\$ 33,094	\$ 35,993

(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, transportation and direct production costs.

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

(4) Repair and maintenance supplies in crude refining and oil sands supplies.

Inventories are valued at the lower of cost and net realizable value ("NRV"). As a result of changes in cost and NRVs, inventory valuation writedowns previously taken were reversed in the amount of \$5.4 million in the nine months ended September 30, 2009 and credited to "Downstream-Crude Oil Purchases and Operating Costs" in the Consolidated Statement of Operations; three months ended September 30, 2009 – nil. For the nine months ended September 30, 2008, a writedown of \$900,000 was recorded, as NRVs were lower than cost; three months ended September 30, 2008 – nil.

Included in "Downstream Crude Oil Purchases and Operating Costs" for the three months ended September 30, 2009 was \$77 million of inventory costs; three months ended September 30, 2008 – \$117 million; nine months ended September 30, 2009 – \$157 million; nine months ended September 30, 2008 – \$291 million.

6. ASSET RETIREMENT OBLIGATIONS

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

(\$000)	Nine months ended September 30, 2009	Year ended December 31, 2008
Asset retirement obligations, beginning of period	\$ 26,396	\$ 24,365
Liabilities incurred	4,542	1,496
Liabilities settled	(156)	(209)
Change in estimated future cash flows	-	(960)
Accretion expense	1,573	1,704
Asset retirement obligations, end of period	\$ 32,355	\$ 26,396

Liabilities incurred in 2009 have been estimated using a discount rate of 10 percent reflecting the company's credit-adjusted risk free interest rate given its current capital structure and an inflation rate of two percent. The company has not recorded an asset retirement obligation for the Montana refinery as it is currently the company's intent to maintain and upgrade the refinery so that it will be operational for the foreseeable future. Consequently, it is not possible to estimate a date or range of dates for settlement of any asset retirement obligation related to the refinery.

7. SHARE CAPITAL, CONTRIBUTED SURPLUS AND EQUITY COMPONENT

Authorized

The authorized share capital comprises the following:

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

Issued

Only common shares have been issued by the company.

	Number of Shares	Amount (\$'000)
Share Capital, December 31, 2008	211,181,815	\$ 395,023
Issued for cash in public offering (a)	191,762,500	172,586
Issued upon exercise of options in 2009 (b)	288,171	172
Assigned value of options exercised in 2009		67
Issued to directors under share award plan (c)	327,623	301
Conversion of debentures (d)	7,200	37
Share issue costs, net of income taxes		(6,595)
Share Capital, September 30, 2009	403,567,309	561,591
Contributed Surplus, December 31, 2008		26,053
Stock based compensation for share options in 2009		2,596
Assigned value of options exercised in 2009		(67)
Contributed Surplus, September 30, 2009		28,582
Equity component of Convertible Debentures, December 31, 2008		16,823
Conversion of debentures (d)		(6)
Equity Component, September 30, 2009		16,817
Total Share Capital, Contributed Surplus and Equity Component December 31, 2008		437,899
September 30, 2009		\$ 606,990

(a) June 2009 Common Share Issue

In June 2009, the company issued from treasury 191,762,500 common shares at \$0.90 per common share, for gross proceeds of \$172.6 million.

(b) Stock Options

A summary of the company's outstanding stock options, as at September 30, 2009 and 2008 and changes during those periods is presented below:

For the nine months ended September 30	2009		2008	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Outstanding, beginning of period	16,383,104	\$ 3.16	17,432,717	\$ 3.60
Granted	5,114,047	\$ 0.75	3,200,495	\$ 3.31
Exercised	(288,171)	\$ 0.60	(1,101,583)	\$ 0.81
Expired	(5,323,783)	\$ 4.50	(378,165)	\$ 4.09
Outstanding, end of period	15,885,197	\$ 1.98	19,153,464	\$ 3.70
Exercisable, end of period	9,868,030	\$ 2.45	13,309,251	\$ 3.74

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

Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life at September 30, 2009
\$0.20 - \$0.99	5,425,637	3.9
\$1.00 - \$1.99	4,321,645	3.1
\$2.00 - \$3.99	5,180,406	2.1
\$4.00 - \$5.56	957,509	1.7
	15,885,197	3.0

In the third quarter of 2009 a non-cash charge of \$623,000 (2008 - \$790,000) was expensed, reflecting the fair value of stock options amortized over the vesting period and the fair value of shares granted to directors. A further \$162,000 (2008 - \$20,000) was capitalized to property and equipment.

During the first nine months of 2009 a non-cash charge of \$2.4 million (2008 - \$3.5 million) was expensed, reflecting the fair value of stock options amortized over the vesting period and the fair value of shares granted to directors. A further \$669,000 (2008 - \$1.0 million) was capitalized to property and equipment.

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

For the nine months ended September 30	2009	2008
Risk free interest rate	1.3%	3.2%
Expected option life (years)	3	3
Expected volatility	68%	48%

The weighted average fair value at the date of grant of all options granted in the first nine months of 2009 was \$0.34 per option (2008 - \$1.18) and for the three months ended September 30, 2009 was \$0.47 per option (2008 - \$1.36).

(c) Share award plan for non-employee directors

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

In January 2009, 108,975 common shares were issued to non-employee directors in respect of the share units which were then vested. In March 2009, the Board of Directors, on the recommendation of the Governance Committee, voted to accelerate the vesting of 218,648 share units originally scheduled to vest on January 1, 2010 and January 1, 2011 such that they vested immediately. These shares were issued in April 2009. Concurrently, an additional 478,872 share units were granted with vesting on January 1, 2010. In the first quarter of 2009, 54,662 share units held by a deceased director were cancelled.

A total of 489,292 share awards were outstanding at September 30, 2009 and have vested or vest on the following dates:

Vested	5,210
December 31, 2009	5,210
January 1, 2010	478,872
	489,292

In the third quarter of 2009, a non-cash charge of \$193,000 (2008 - \$12,000) was accrued as a liability and expensed in respect of shares yet to be issued under the share award plan. In the first nine months of 2009, a non-cash charge of \$516,000 (2008 - \$445,000) was accrued as an expense and a liability in respect of shares to be issued under the plan.

(d) Conversion of debentures

In June 2009, \$36,000 principal amount of Convertible Debentures were converted into 7,200 common shares. A portion of each of the liability and equity components of the debenture together with the principal amount were transferred to share capital. No gain or loss was recorded.

8. SEGMENTED INFORMATION

The company has two business segments. In Canada, the company is in the business of exploring for and producing crude oil, natural gas and bitumen. In the U.S., the company is in the business of refining and marketing petroleum products.

Three months ended September 30

(\$000)	Upstream Canada Oil and Gas	Downstream USA Refining	Intersegment Elimination ⁽¹⁾	Total
2009				
Revenues, net of royalties	\$ 58,709	\$ 92,714	\$ (2,252)	\$ 149,171
Equity interest in Petrolifera loss	(2,797)	-		(2,797)
Dilution loss	(2,593)	-		(2,593)
Interest and other income	2,006	183		2,189
Finance charges	13,120	7		13,127
Depletion, depreciation and accretion	14,864	1,827		16,691
Tax provision	5,254	1,088		6,342
Net earnings	45,162	2,605		47,767
Property and equipment, net	1,045,583	85,622		1,131,205
Goodwill	103,676	-		103,676
Capital expenditures	92,207	8,520		100,727
Total assets	\$ 1,557,824	\$ 178,302		\$ 1,736,126
2008				
Revenues, net of royalties	\$ 96,291	\$ 127,726		\$ 224,017
Equity interest in Petrolifera earnings	854	-		854
Dilution loss	(60)	-		(60)
Interest and other income	434	107		541
Finance charges	7,536	250		7,786
Depletion, depreciation and accretion	13,484	1,484		14,968
Tax provision (recovery)	2,910	(1,290)		1,620
Net earnings	11,711	428		12,139
Property and equipment, net	837,256	71,084		908,340
Goodwill	103,676	-		103,676
Capital expenditures	62,259	6,916		69,175
Total assets	\$ 1,235,262	\$ 134,271		\$ 1,369,533

Nine months ended September 30

(\$000)	Upstream Canada Oil and Gas	Downstream USA Refining	Intersegment Elimination ⁽¹⁾	Total
2009				
Revenues, net of royalties	\$ 120,737	\$ 194,960	\$ (5,724)	\$ 309,973
Equity interest in Petrolifera loss	(1,658)	-		(1,658)
Dilution loss	(2,593)	-		(2,593)
Interest and other income	2,797	566		3,363
Finance charges	30,796	368		31,164
Depletion, depreciation and accretion	44,187	5,491		49,678
Tax provision (recovery)	(107)	(59)		(166)
Net earnings	39,924	965		40,889
Property and equipment, net	1,045,583	85,622		1,131,205
Goodwill	103,676	-		103,676
Capital expenditures	189,930	15,288		205,218
Total assets	\$ 1,557,824	\$ 178,302		\$ 1,736,126
2008				
Revenues, net of royalties	\$ 207,700	\$ 317,445		\$ 525,145
Equity interest in Petrolifera earnings	2,244	-		2,244
Dilution gain	7,964	-		7,964
Interest and other income	1,745	340		2,085
Finance charges	22,107	408		22,515
Depletion, depreciation and accretion	32,129	4,128		36,257
Tax provision (recovery)	4,740	(3,433)		1,307
Net earnings (loss)	19,072	(2,083)		16,989
Property and equipment, net	837,256	71,084		908,340
Goodwill	103,676	-		103,676
Capital expenditures	250,691	14,872		265,563
Total assets	\$ 1,235,262	\$ 134,271		\$ 1,369,533

(1) Intersegment transactions are eliminated on consolidation.

9. SUPPLEMENTARY INFORMATION

(a) Per share amounts

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

For the three months ended September 30 (000)	2009	2008
Weighted average common shares outstanding	403,565	211,093
Dilutive effect of stock options, share units under the non-employee directors share award plan and Convertible Debentures	20,493	2,081
Weighted average common shares outstanding – diluted	424,058	213,174

For the nine months ended September 30 (000)	2009	2008
Weighted average common shares outstanding	294,463	210,663
Dilutive effect of stock options, share units under the non-employee directors share award plan and Convertible Debentures	406	2,623
Weighted average common shares outstanding – diluted	294,869	213,286

The Convertible Debentures, stock options and share units were anti-dilutive to the loss per share calculation for the nine months ended September 30, 2009.

(b) Net change in non-cash working capital

For the three months ended September 30 (\$000)	2009	2008
Accounts receivable	\$ 30	\$ 16,400
Inventories	15,682	11,611
Due from Petrolifera	27	(57)
Prepaid expenses	(16,568)	(1,519)
Accounts payable and accrued liabilities	53,817	6,480
Income taxes payable/recoverable	(2,355)	4,679
Total	\$ 50,633	\$ 37,594

Summary of working capital changes:		
Operations	\$ 25,074	\$ (114)
Investing	25,559	37,708
	\$ 50,633	\$ 37,594

For the nine months ended September 30 (\$000)	2009	2008
Accounts receivable	\$ (27,419)	\$ (17,944)
Inventories	(4,137)	(7,551)
Due from Petrolifera	(6)	(20)
Prepaid expenses	(19,264)	(335)
Accounts payable and accrued liabilities	4,754	55,144
Income taxes payable/recoverable	(3,486)	4,358
Total	\$ (49,558)	\$ 33,652

Summary of working capital changes:		
Operations	\$ (25,594)	\$ 8,793
Investing	(23,964)	24,859
	\$ (49,558)	\$ 33,652

(c) Supplementary cash flow information

For the three months ended September 30 (\$000)	2009	2008
Interest paid	\$ 160	\$ 787
Income taxes paid	250	132

For the nine months ended September 30 (\$000)	2009	2008
Interest paid	\$ 37,565	\$ 36,123
Income taxes paid	1,613	1,504

At September 30, 2009 cash of \$10 million was restricted to provide credit support for the letters of credit (Note 4(f)).

(d) Dilution gains and losses

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

In the third quarter of 2009, Petrolifera issued 66.5 million Units to raise \$58 million. Each Unit was comprised of one Petrolifera common share and one-half of a Petrolifera Share Purchase Warrant. Each full Petrolifera Share Purchase Warrant is exercisable to purchase one Petrolifera common share at \$1.20 per common share over a period not exceeding two years. Connacher subscribed for 13,556,000 Units. On September 1, 2009 Connacher also exercised its options to purchase an additional 200,000 Petrolifera common shares at \$0.50 per common share. These transactions resulted in a dilution loss of

\$2.6 million in the third quarter of 2009. Connacher now holds 26.9 million Petrolifera common shares, representing 22 percent of Petrolifera's issued and outstanding common shares and 6.8 million Petrolifera Share Purchase Warrants.

(e) Defined benefit pension plan

In the first nine months of 2009, \$364,000 (2008 – \$344,000) and for the three months ended September 30, 2009 – \$70,000 (2008 – \$117,000) was charged to expense in relation to MRCL's defined benefit pension plan.

10. SUBSEQUENT EVENT

In October 2009, the company issued from treasury 23,172,500 common shares on a flow-through basis at \$1.30 per share for gross proceeds of \$30 million, to fund the company's winter exploration program.