SECOND QUARTER REPORT

FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2013

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") for Connacher Oil and Gas Limited ("Connacher" or the "Company") is dated August 14, 2013 and should be read in conjunction with Connacher's condensed interim consolidated financial statements for the three months ended June 30, 2013 ("Q2 2013") and for the three months ended June 30, 2012 ("Q2 2012") and for the six months ended June 30, 2013 ("YTD 2013") and for the six months ended June 30, 2012 ("YTD 2012") and the consolidated financial statements for the years ended December 31, 2012 and 2011.

The condensed interim consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). Unless otherwise indicated, all references to $ in this MD&A are to Canadian dollars. References to US$ herein are to United States dollars.

Please read the Advisory section of the MD&A which provides information on Forward Looking Information, Non–GAAP Measurements and other information. Additional information relating to Connacher, including Connacher's Annual Information Form for the year ended December 31, 2012 ("AIF"), can be found on the System for Electronic Document Analysis and Retrieval ("SEDAR") at www.sedar.com or on the Company's website at www.connacheroil.com.

PRESENTATION AND ANALYSIS OF OPERATING RESULTS

The Company fully exited its downstream refining business and its conventional oil and gas business ("Discontinued Operations"), effective October 1, 2012 and September 14, 2012, respectively. Connacher is a focused *in situ* oil sands developer, producer and marketer of bitumen. The following MD&A focuses on the financial and operating results of Connacher's continuing oil sands business.

OVERVIEW

The Company holds a 100% interest in approximately 500 million barrels of proved and probable bitumen reserves and operates two steam assisted gravity drainage ("SAGD") facilities located on the Company's Great Divide oil sands leases near Fort McMurray, Alberta.

Connacher's two producing projects at Great Divide are known as Pod One and Algar. Pod One began production in 2007 achieving commercial production Q1 2008. A total of 23 SAGD well pairs and four infill wells have been drilled to date from three well pads located at Pod One, including four new well pairs drilled in the first half of 2013.

Algar began production in August 2010 and achieved commerciality in October 2010. A total of 18 SAGD well pairs, including a new replacement well pair on Pad 202 in Q1 2013, have been drilled to date from three well pads.

The Company received regulatory approval for the Great Divide expansion project in September 2012. The expansion would be completed entirely within the existing Algar central processing facility area at Great Divide.

Connacher received regulatory approval in Q2 2013 for a SAGD+ commercial project for all of the existing Algar well pads, and to divert steam from older, lower producing wells at Pad 101 North to the new well pairs at Pad 104 in July 2013.

Q2 FINANCIAL AND OPERATIONAL HIGHLIGHTS

FINANCIAL

- Q2 2013 revenue, net of royalties, was $110.6 million up 36% from Q2 2012 ($81.4 million) due to higher realized pricing
- Diluent costs decreased by 15% to $30.5 million in Q2 2013 ($35.7 million in Q2 2012) and to $67.5 million YTD 2013 from $77.9 million. Decreased diluent costs resulted from a lower diluent blend ratio ("DBR") which was achieved by ongoing improvements in operational procedures

- Bitumen netback was $34.0 million, up 125% from Q2 2012 ($15.1 million), due to higher realized prices and lower diluent usage, partially offset by higher costs associated with increasing rail volumes and higher natural gas costs
- EBITDA was $24.4 million in Q2 2013 (Q2 2012 $7.0 million) and $35.1 million YTD 2013 (YTD 2012 $19.4 million)
- Q2 2013 funds flow from continuing operations was $6.0 million compared to a use of funds of $14.2 million in Q2 2012
- The Company realized a net loss from continuing operations of $32.1 million in Q2 2013 (YTD 2013 net loss $78.7 million) compared to a net loss of $20.3 million in Q2 2012 (YTD 2012 net loss $43.3 million). The increase in net loss from continuing operations is primarily due to an increase in non-cash and unrealized charges. Unrealized gains on risk management contracts decreased from a gain of $26.8 million in Q2 2012 to a gain of $2.7 million in Q2 2013. Unrealized foreign exchange losses increased to $18.3 million in Q2 2013 from $9.7 million in Q2 2012, primarily due to mark-to-market on the foreign currency value of our US dollar denominated portion of our long-term debt
- Connacher closed the quarter with cash on hand of $76.7 million and available credit facilities of $81.7 million, net of outstanding letters of credit
- Q2 2013 capital expenditures totaled $28.4 million and focused primarily on completion of our 2013 drilling program. This consisted of four infill wells on Pad 102 and four new well pairs at Pad 104. All of the wells were completed in Q2 2013. Construction of surface facilities and tie-in is continuing at both pads

PRODUCTION

- Connacher's production for Q2 2013 averaged 11,572 bbl/d compared to 11,674 bbl/d for Q2 2012. Pod One production averaged 5,660 bbl/d and Algar averaged 5,912 bbl/d

OPERATIONS

- Diluent use averaged 2,971 bbl/d in Q2 2013 resulting in a DBR of 20%, a 16% reduction from Q2 2012 of 3,558 bbl/d (24% DBR). Reducing diluent usage has been a key focus of our operations, and due to this success we do not plan to complete the Diluent Recovery Unit (the "DRU"). Tankage previously built for the DRU will be tied into Pod One to increase on-site storage capacity

MARKETING AND RISK MANAGEMENT

- In Q2 2013, bitumen volumes shipped to rail destinations outside of Alberta averaged approximately 9,400 bbl/d (80% of sales) compared to approximately 6,800 bbl/d (55% of sales) in Q1 2013 and approximately 2,300 bbl/d (19% of sales) in Q2 2012. The balance of sales are to intra-Alberta markets
- For the balance of 2013, the Company has approximately 7,500 bbl/d of production hedged at WTI prices ranging from US$90-$105. For 2014 the Company has approximately 4,700 bbl/d hedged at WTI prices ranging from US$90-$96

PROJECTS

- We expect to begin steaming the new well pairs at Pad 104 at the end of Q3 2013. These well pairs will be converted to production by the end of Q4 2013
- Three of four Pad 102 infill wells began steaming in late July and are expected to be converted to production in Q4 2013. The remaining infill well was recently placed on steam injection
- The replacement well pair on Pad 202 at Algar was placed on production in early July
- As a result of the SAGD+ trial on well pair 203-1 at Algar, average bitumen production rates were approximately 30% higher in the first four months of 2013 than the four months prior to the beginning of the test in May 2012. Steam injection was approximately 10% less over the same comparative period. Solvent injection rates over the entire test period have averaged 6% of the steam volume injected and it is estimated that 92% of the cumulative solvent injected has been recovered. Five months into the test on 203-1, the SOR reached 3.0; approximately 33% lower than SORs prior to the test, and have remained at these lower values despite changes to the steam rate. In May 2013 the producer well at 203-1 was converted from gas lift to a submersible pump and the results of this change are being assessed

- 203-4 solvent injection began in July. The trial will continue on both 203-1 and 203-4 pairs through the end of 2013. We are also planning to add an additional trial on at least one of the new well pairs at Pad 104

- Connacher received regulatory approval in Q2 2013 for a SAGD+ commercial project for all of the existing Algar well pads, and to divert steam from older, lower producing wells at Pad 101 North to the new well pairs at Pad 104 in July 2013. The SAGD+ commercial project will continue to be evaluated as part of our 2014 capital plan

LIQUIDITY AND CAPITAL RESOURCES

At June 30, 2013, the Company's working capital surplus was $56.6 million (June 30, 2012 – $110.6 million), including $76.7 million of cash on hand (June 30, 2012 - $41.5 million).

Cash flow from operating activities (continuing operations) was $21.2 million in Q2 2013 compared to $18.0 million in Q2 2012. The increase was primarily driven by higher realized pricing, partially offset by higher transportation and handling costs.

Cash flow used in investing activities on continuing operations was $26.6 million in Q2 2013 compared to $15.1 million in Q2 2012. The primary driver was an increase in capital spending of $19.7 million offset by a decrease in non-cash working capital of $6.0 million. Details of capital expenditures are discussed further in the "Capital Expenditures" section of this MD&A.

Cash flow used in financing activities decreased to nil in Q2 2013 from $22.0 million in Q2 2012 due to the repayment of Convertible Debentures in June 2012 offset by borrowing on the revolving credit facility.

LIQUIDITY

SOURCE OF FUNDS

As at June 30, 2013	Amount ($ 000)	Term
Cash and cash equivalents	$76,724	Not applicable
Revolving Credit Facility(1)	$81,704	May 31, 2014

(1) The Company's Revolving Credit Facility (the "Facility") has a borrowing base of $95 million, subject to commitments for letters of credit and covenant restrictions

At June 30, 2013, the Company had no outstanding borrowings under the Facility with the exception of $13.3 million that has been utilized to back–stop various letters of credit. The maximum currently available to borrow is $81.7 million ($95 million less existing letters of credit).

Under the note indenture for the Company's existing Second Lien Senior Notes, the Company has a first lien debt basket that permits the Company to incur first lien debt of up to $170 million (inclusive of commitments under the Facility).

See "Capital Resources" for further details.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

In the normal course of business, the Company is obligated to make future payments. These obligations represent contracts and other commitments that are known and non–cancellable. Refer to the Company's 2012 annual MD&A which summarizes contractual obligations and commitments as at December 31, 2012. At June 30, 2013, the Company had contractual obligations and commitments of $3.7 million in addition to those that existed as at December 31, 2012.

The Company is obligated to make payments under these additional commitments as follows:

Incurred in the six months ended June 30, 2013 ($ 000)	2013	1-3 years	4-6 years	Thereafter	Total
Operating leases(1)	$458	$1,914	$619	$-	$2,991
Other commitments(2)	156	549	-	-	705
Total	$614	$2,463	$619	$-	$3,696

(1) Includes vehicle leasing costs and $2.6 million with respect to rail car contracts
(2) Primarily relates to IT service costs

OFF BALANCE SHEET ITEMS

At June 30, 2013, the Company had no off-balance sheet arrangements other than letters of credit to various trade creditors or governments outstanding under the Facility of $13.3 million (June 30, 2012 – $2.2 million).

CAPITAL RESOURCES

OUTSTANDING DEBT[1]

($ 000)	June 30, 2013	December 31, 2012
Second Lien Senior Notes, 8.75%, due August 1, 2018 ($350 million face value)	**344,367**	343,939
Second Lien Senior Notes, 8.5%, due August 1, 2019 (US$ 550 million face value)	**537,029**	505,999
Total	**$881,396**	$849,938

(1) Amounts are shown net of unamortized discounts and transaction costs

REVOLVING CREDIT FACILITY

The Facility provides for revolving credit financings of up to $95 million, subject to borrowing base availability, including sub–facilities for letters of credit, swingline loans and borrowings in Canadian dollars and U.S. dollars.

As of June 30, 2013, the Company had letters of credit outstanding under the Facility of $13.3 million.

As at June 30, 2013 the maximum available to borrow, under the Facility, is $81.7 million ($95 million less existing letters of credit).

All outstanding loans under the Facility are due and payable in full on May 31, 2014. The Facility bears interest at the rate of Canadian or US prime rate plus applicable margin in addition to a stand–by fee.

The Facility contains a requirement to maintain a ratio of consolidated total debt to total capitalization of under 75% (with $120 million added to equity for IFRS conversion adjustments) and borrowings under the Facility cannot exceed two times trailing four quarters EBITDA.

Four quarter trailing EBITDA (continuing operations) is approximately $56.4 million at Q2 2013. As two times the trailing four quarter EBITDA is in excess of the borrowing base of the Facility of $95 million the Company is currently able to fully draw on the Facility. In the event that EBITDA from continuing operations declines in future quarters, the borrowing base could decline. EBITDA has been adjusted for Discontinued Operations for all prior periods for the purpose of this calculation.

All obligations under the Facility are unconditionally guaranteed by the Company and are secured by substantially all of the assets of the Company, including a first priority security interest on all current and future property.

SENIOR NOTES

The Company issued US$550 million face value 8.5% Second Lien Senior Notes due August 1, 2019 and $350 million face value 8.75% Second Lien Senior Notes due August 1, 2018 at par (collectively the “Notes”) on May 31, 2011. Interest is payable semi–annually on February 1 and August 1 each year the Notes are outstanding. The Notes are secured on a second priority basis by liens on all of the Company’s existing and future property.

SHAREHOLDERS EQUITY AND SHARES OUTSTANDING

At June 30, 2013 the Company reported shareholders equity of $265.0 million (December 31, 2012 $342.9 million). Changes in shareholders equity are due to losses from continuing operations and are discussed in the Financial and Operating Review Section of this MD&A.

As at June 30, 2013, the Company had the following securities issued and outstanding:

- 449,719,792 common shares
- 19,355,284 stock options under the Company’s Stock Option Plan
- 2,725,000 share units under the Share Award Incentive Plan
- 1,697,686 share units under the Share Unit Plan

Subsequent to June 30, 2013, the following additional securities were issued by the Company:

- 66,000 stock options under the Company’s Stock Option Plan

FINANCIAL AND OPERATING REVIEW

The financial and operating review has been split into Continuing Operations (the Great Divide oil sands in northeastern Alberta) and Discontinued Operations, which consists of the downstream refining business (the "Refinery") and the conventional petroleum and natural gas assets previously owned by Connacher. As previously disclosed, the Refinery was sold effective October 1, 2012 and the Company’s conventional assets were sold September 14, 2012. Prior period information has been restated to reflect the effect of

Discontinued Operation; as such the Refinery and conventional assets are not included in the consolidated results from Continuing Operations of Connacher.

CONTINUING OPERATIONS

PRODUCTION AND SALES VOLUMES[1]

	Three months ended June 30			Six months ended June 30		
	2013	2012	% Change	**2013**	2012	% Change
Dilbit sales – bbl/d	**14,713**	14,871	**(1)**	**15,472**	15,660	(1)
Diluent used – bbl/d	**(2,971)**	(3,558)	**(16)**	**(3,264)**	(3,729)	(12)
Bitumen sold – bbl/d	**11,742**	11,313	**4**	**12,208**	11,931	2
Bitumen production volumes – bbl/d [2]	**11,572**	**11,674**	**(1)**	**11,986**	12,052	(1)

(1) Bitumen produced at oil sands projects is mixed with purchased diluent and sold as “dilbit”. Diluent volumes used have been deducted in calculating bitumen production and sales volumes
(2) The Company’s bitumen sales volumes differ from its production volumes due to changes in inventory and other product losses

COMMODITY PRICES AND RISK MANAGEMENT

	Three months ended June 30			Six months ended June 30		
Average benchmark prices	**2013**	2012	% Change	**2013**	2012	% Change
West Texas Intermediate (WTI) US$/bbl	**94.27**	93.50	**1**	**94.96**	98.20	**(3)**
Heavy Oil Differential – C$/bbl [1]	**17.13**	23.00	**(26)**	**22.12**	22.21	**-**
Western Canadian Select (WCS) – C$/bbl	**79.04**	71.31	**11**	**74.18**	76.48	**(3)**
Edmonton C5 – (C$/bbl) [2]	**104.32**	100.36	**4**	**101.50**	105.29	**(4)**
Natural Gas (Alberta spot) C$/mcf at AECO	**3.36**	1.91	**76**	**3.20**	1.71	**87**

(1) Heavy oil differential refers to the WCS discount to WTI
(2) Edmonton C5 is the benchmark price for diluent

Connacher employs a marketing strategy that accesses multiple markets outside of Alberta via rail. In Q2 2013 Connacher railed approximately 80% of its bitumen sales volumes. The balance of sales are to intra-Alberta markets.

Actual realized bitumen price is a calculated amount derived by deducting from the dilbit sales price such items as the cost of diluent, transportation and handling charges for both diluent from purchase points to the Company’s Great Divide site and for dilbit sales from the Company’s Great Divide site to market. Other factors which influence calculated bitumen prices include the value of the Canadian dollar relative to the US dollar, the DBR and variations in heavy oil differentials.

Connacher’s dilbit is generally sold using month-to-month or longer fixed term sales contracts at prices negotiated with Canadian or U.S. customers, by reference to various benchmark prices, including WTI and WCS market prices. Connacher maintains various contracts for the sale of dilbit to a variety of customers in Canada and the United States.

As a means of managing the risk of commodity price volatility, management monitors various crude oil markets and enters into risk management commodity sales contracts to provide Connacher with downside commodity price risk protection on a portion of its production. Connacher enters into risk management contracts primarily for WTI and when available, WCS benchmarks. As WCS pricing is quoted as a differential to WTI, it is necessary to hedge both WTI, (to fix the underlying benchmark), and WCS (to fix the maximum differential to WTI) thus providing a floor price for volumes that are sold or contracted based on WCS pricing. The risk management markets are not liquid for WCS. With very low volume the market trading is extremely limited beyond one calendar year with very wide bid/ask spreads. Thus the Company has no WCS risk management contracts in place at this time.

The hedging policy is established by the Board of Directors, having consideration for financial leverage and capital commitments and restrictions detailed in the Facility. The hedging program is administered by a management subcommittee comprised of appropriate departmental representatives operating within Board approved hedging parameters.

The Company had the following WTI crude oil price risk management positions in place at August 14, 2013 using a combination of swaps and costless collars:

WTI - Term	Notional Volume (bbl/day)	Min Price[(1)] (WTI US$/bbl)	Max Price[(1)] (WTI US$/bbl)
Jul – Sept, 2013	7,550	93.21	103.35
Oct – Dec, 2013	7,650	92.97	100.45
Jan – Mar, 2014	4,700	89.50	95.09
Apr – June, 2014	4,700	90.05	95.52
July – Sept, 2014	4,700	90.87	94.85
Oct – Dec, 2014	4,200	90.96	95.42

(1) Weighted average price of risk management contracts. Contracts that are in Canadian dollars are converted at CA$=0.967US$

Additionally the Company has sold swaptions for 2,975 bbl/day at a weighted average of WTI US$98.17 for the period January 1, 2014 – December 31, 2014, and 1,500 bbls/day at a weighted average of WTI US$95 for the period January 1, 2015 – December 31, 2015 exercisable on December 31, 2013 and 2014 respectively, at the counterparty's option.

Swaptions are typically entered into as an extension of a swap and provides our counterparties a call option to extend that swap for a predetermined term and price, and are exercisable on the last business day of the expiring swap term. Premiums from entering into swaptions are used to increase the price of the underlying contract.

BITUMEN NETBACK[(1)]

	Three months ended June 30		Six months ended June 30	
($ 000)	**2013**	2012	**2013**	2012
Dilbit sales[(2)]	**$113,885**	$83,918	**$217,822**	$194,926
Diluent costs[(3)]	**(30,515)**	(35,747)	**(67,488)**	(77,920)
Realized bitumen sales	**83,370**	48,171	**150,334**	117,006
Royalties	**(3,272)**	(2,507)	**(5,889)**	(5,768)
Transportation and handling costs	**(23,132)**	(12,847)	**(46,378)**	(23,910)
Net bitumen revenues	**56,966**	32,817	**98,067**	87,328
Production and operating expenses	**(23,006)**	(17,913)	**(45,357)**	(37,838)
Bitumen netback	**$33,960**	$14,904	**$52,710**	$49,490

(1) A non-GAAP measure which is defined in the Advisory section of the MD&A. Oil sands netback is reconciled to net loss under "Reconciliations of Oil Sands Netbacks and EBITDA from Continuing Operations to Net Loss" in this MD&A

(2) Bitumen produced at oil sands projects is mixed with purchased diluent and sold as "dilbit". Dilbit sales are presented before royalties. In the consolidated financial statements, revenues are presented net of royalties. Risk management gains or losses are not included

(3) The cost of diluent has been deducted from dilbit sales in calculating realized bitumen sales above, whereas the diluent costs have been included in "Blending and costs of product sold" in the consolidated financial statements. Diluent costs above include purchases of $4.3 million in Q2 2012 and $9.3 million in the six months ended June 30, 2012, from the Refinery which were transacted at prevailing market prices

Diluent used represented approximately 20% of the dilbit barrel sold in Q2 2013 (24% in Q2 2012). The lower DBR was a result of improved plant operating efficiencies.

In Q2 2013, 2,971 bbl/d of diluent was used at a cost of $112.89 per bbl, and includes diluent transportation and handling costs (3,588 bbl/d was used at a cost of $110.41 per bbl in Q2 2012).

Transportation and handling costs were higher in Q2 2013 compared to Q2 2012 primarily due to higher volumes of dilbit moving by rail (approximately 80% moving by rail in Q2 2013 versus 19% in Q2 2012). With increased rail volumes, Connacher has achieved higher realized pricing, and higher netbacks than would have otherwise been achievable through traditional markets.

The table below summarizes information related to oil sands production and operating expenses:

	Three months ended June 30		Six months ended June 30	
($ 000)	**2013**	2012	**2013**	2012
Natural gas costs	**$7,537**	$4,201	**$14,382**	$8,933
Other production and operating expenses	**15,469**	13,512	**30,975**	28,905
Total production and operating expenses	**$23,006**	$17,713	**$45,357**	$37,838

Total production and operating expenses increased by 30% from Q2 2012, predominantly due to higher natural gas costs as AECO benchmark pricing has increased by 76% from 2012. Natural gas is a primary energy input cost for the Company, as it is used to generate steam for the SAGD process, and to create electricity from the Company's cogeneration facility at Algar.

The cogeneration facility allows the Company to improve reliability of its electricity supply by generating substantially all of its electricity needs on site. Steam generated through the cogeneration plant is then subsequently reused to supplement Algar's SAGD operations. The cost of generating electricity from the cogeneration plant is currently less than what the Company would have paid for electricity from the Alberta electrical grid.

BITUMEN NETBACK – $ PER BARREL

	Three months ended June 30			Six months ended June 30		
	2013	2012	% Change	**2013**	2012	% Change
Dilbit sales	**$85.06**	$62.01	37	**$77.78**	$68.39	14
Diluent costs[1]	**(7.03)**	(15.22)	(54)	**(9.75)**	(14.51)	(33)
Realized bitumen sales[2]	**78.03**	46.79	67	**68.03**	53.88	26
Transportation and handling costs	**(21.65)**	(12.48)	73	**(20.99)**	(11.01)	91
	56.38	34.31	64	**47.04**	42.87	10
Royalties	**(3.06)**	(2.43)	26	**(2.67)**	(2.66)	-
Net bitumen revenue	**53.32**	31.88	67	**44.37**	40.21	10
Production and operating expenses	**(21.53)**	(17.21)	25	**(20.53)**	(17.33)	18
Bitumen netback – per barrel	**$31.79**	$14.67	117	**$23.84**	$22.88	4

(1) Diluent costs represents the cost of diluent in excess of dilbit selling price
(2) Before risk management contract gains or losses

Realized bitumen sales per barrel, after transportation increased by 64% in Q2 2013 from Q2 2012.

Transportation costs have increased slightly from Q1 2013 ($20.37/bbl) to 21.65/bbl in Q2 2013.

Bitumen netbacks have increased 93% from Q1 2013 to Q2 2013 primarily due to increased revenue resulting from a 20% increase in realized dilbit sales price combined with a 600 bbl/d decrease in diluent usage resulting in savings of $6.5 million over the prior quarter.

CORPORATE REVIEW

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses in Q2 2013 were $7.1 million (YTD 2013 $14.7 million) compared to $6.6 million in Q2 2012 (YTD 2012 $24.4 million).

SHARE-BASED COMPENSATION

Share-based compensation expense was $435 thousand in Q2 2013 (YTD 2013 $872 thousand), compared to $343 thousand in Q2 2012 (YTD 2012 $1,017 thousand).

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

	Three months ended June 30		Six months ended June 30	
($ 000)	**2013**	2012	**2013**	2012
Oil sands assets	**$21,325**	$19,317	**$42,017**	$40,160
Corporate assets	**401**	458	**781**	867
Capitalized to inventory	**40**	-	**355**	-
Total	**$21,766**	$19,775	**$43,153**	$41,027

Depletion expense is calculated using the unit–of–production method, based on estimated total proved and probable ("2P") reserves. Future capital costs estimated to realize production from the Company's 2P reserves are added to the carrying amount of capitalized costs for depletion purposes. Depletion expense was slightly higher in 2013 relative to 2012 primarily as a result of higher expected future capital costs reflecting current industry conditions in the oil sands. Corporate assets are depreciated over their estimated useful lives.

FINANCE CHARGES

Finance charges for Q2 2013 were $21.9 million (YTD 2013 $43.7 million) compared to $23.8 million in Q2 2012 (YTD 2012 $46.9 million). Finance charges include interest expense relating to the Notes and the Facility, amortization of transaction costs of the Facility, standby fees associated with the Facility, fees on letters of credit issued and bank charges. Finance charges also include non–cash charges with respect to the Notes and unwinding of discounts on decommissioning liabilities. Lower finance charges in 2013 compared to 2012 were primarily due to lower cash interest costs due to the repayment of the Convertible Debentures on June 30, 2012 and the repayment of the previously outstanding senior notes in January 2012.

FOREIGN EXCHANGE

The fluctuation of the value of the Canadian dollar relative to the U.S. dollar has an impact on Connacher's results when settling U.S. dollar–denominated transactions and translating U.S. dollar–denominated long–term debt and U.S. dollar cash balances into Canadian dollars for financial reporting purposes. The Company recorded a foreign exchange loss of $17.4 million in Q2 2013 (Q2 2012 foreign exchange loss of $9.8 million).

In order to mitigate the foreign exchange risk on US$ denominated revenue the Company has the following contracts outstanding:

- Sell US$5 million/buy CA$5 million settling February 2013 - January 2014 (total value US$60 million/CA$59.4 million)
- Sell US$5 million/buy CA$5 million settling February 2013 - January 2014 (total value US$60 million/CA$60 million)

GAIN ON DISPOSITION OF ASSETS

In Q2 2013, the Company realized a gain of $2.1 million on disposition and de-recognition of assets in the normal course of operations (Q2 2012 loss of $419 thousand).

INCOME TAXES

No income tax provision was recorded in Q2 2013 (Q2 2012 $nil) as the Company's available deductions for income taxes exceed its taxable income in the period. Further, the Company has recorded no net deferred tax liabilities.

EBITDA, FUNDS FLOW AND NET LOSS

EBITDA was $24.4 million in Q2 2013 (YTD 2013 $35.1 million) compared to $7.0 million reported in Q2 2012 (YTD 2012 $19.4 million). The increase in EBITDA was primarily due to higher oil sands netbacks driven by higher realized revenue and partially offset by higher transportation and handling costs. Refer to "Non-GAAP Measurements" on page 12 of this MD&A.

Q2 2013 funds flow from continuing operations was of $5.7 million (YTD 2013 use of $3.8 million) compared to a use of $14.2 million reported in Q2 2012 (YTD 2012 $22.6 million). Funds flow from continuing operations was impacted by the same factors that impacted EBITDA from continuing operations.

The Company realized net losses from continuing operations of $32.1 million in Q2 2013 (YTD 2013 $78.7 million) compared to net losses of $20.3 million in Q2 2012 (YTD 2012 $43.3 million). The increase in net loss from continuing operations is primarily due to an increase in non-cash, unrealized charges. Unrealized gains on risk management contracts has decreased from a gain of $26.8 million in Q2 2012 to a gain of $2.7 million in Q2 2013 due primarily to an increase in the volume and term of outstanding contracts as at Q2 2013. As $578 million of our long term debt is denominated in US dollars we have seen an increase in our unrealized (non-cash) foreign exchange losses to $18.3 million in Q2 2013 from $9.7 million in Q2 2012, due to the decrease in the value of the Canadian dollar relative to the US dollar.

CAPITAL EXPENDITURES

ACTUAL CAPITAL EXPENDITURES

Q2 2013 cash capital expenditures were $28.4 million (YTD 2013 $48.7 million). Maintenance activities were $6.9 million. Cash capital expenditures related to projects that are designed to increase production or decrease operating costs ("Growth Capital") were $21.3 million primarily related to development drilling activities and related surface facilities. Corporate cash capital expenditures totaled $0.2 million.

Q2 2012 cash capital expenditures for maintenance activities was $5.7 million, Growth Capital cash expenditures were $2.7 million related to production enhancements and oil sands exploration activities.

Connacher's remaining capital budget for 2013 is $31.5 million for growth focused projects (from a total $68 million) and $19.1 million (from a total $30 million) for normal maintenance. The remaining capital program will be substantially incurred and paid through the remainder of 2013, from cash on hand and operating cash flows.

DISCONTINUED OPERATIONS

As a result of a strategic decision by the Company's Board of Directors, the Company sold its interest in its wholly owned subsidiaries Montana Refining Company, Inc. ("MRCI") and Great Divide Pipeline Corporation for $204.3 million (US$208 million). This allowed the Company to repay all outstanding borrowings and increased the Company's cash position. The Company is no longer subject to the volatility of the refining market and working capital and capital investment requirements that owning and operating a small refinery in the United States entail. In addition, the sale of the refinery reduced the Company's exposure to exchange rate risks. Closing of this transaction occurred on October 1, 2012. The Company recorded a gain in Discontinued Operations of $32.9 million on the sale of MRCI. No cash taxes were paid on the disposition as the Company had sufficient tax pools to offset any taxable gains incurred.

As part of the Company's program to rationalize its oil and gas properties the Company sold all of its remaining conventional petroleum and natural gas properties. The Company recorded a loss of $119 thousand on this sale which was also recorded in Discontinued Operations.

As the Company has fully exited the downstream refinery business and the conventional petroleum and natural gas business, results of operations for both these businesses have been presented as Discontinued Operations for the current and comparative periods in the condensed interim consolidated financial statements. Revenues for the refinery were $214 million and production and operating expenses (including transportation, handling and crude oil purchases) were $181 million, resulting in a refining netback of $33 million during the first half of 2012. Revenues for the conventional oil and gas business during the first half of 2012 were $5 million and production and operating expenses (including transportation, handling and royalties) were $4 million, resulting in a conventional oil and gas netback of $1 million.

For a reconciliation of conventional netbacks and refining netbacks for the three months and six months ended June 30, 2012, please see the Q2 2012 MD&A which is available at www.sedar.com.

Capital expenditures relating to the refinery were $7 million during the first half of 2012 and $100 thousand for the first half of 2012 in respect of conventional oil and gas business. Historically, significant capital expenditures were incurred by the Company in respect of the refinery in connection with annual maintenance and environmental compliance and reporting requirements in the United States.

RISK FACTORS AND RISK MANAGEMENT FOR CONTINUING OPERATIONS

GENERAL

Connacher is engaged in the oil and gas exploration, development and production industry. The business is inherently risky and there is no assurance that hydrocarbon reserves will be discovered and economically produced and sold. Operational risks include reservoir performance uncertainties, environmental factors, competition 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 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 of third parties and other risks and uncertainties described in more detail in Connacher's AIF filed with securities regulatory authorities.

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

COMMODITY PRICE AND EXCHANGE RATE RISKS

Connacher's future financial performance remains closely linked to crude oil and natural gas prices and foreign exchange rate changes which may be influenced by many factors including global and regional supply and demand, seasonality, political events and weather. These factors can cause a high degree of price volatility. The Company mitigates some of the risk associated with changes in commodity prices through the use of hedges and other derivative financial instruments.

Dilbit sale and diluent purchase prices are based on U.S. dollar benchmarks that result in realized prices being influenced by the US:Canadian dollar exchange rate, thereby creating another element of uncertainty. Should the Canadian dollar strengthen compared to the U.S dollar, the resulting negative effect on revenue would be partially offset with exchange gains on translating U.S. dollar denominated debt and associated interest payments thereon. The opposite would occur should the Canadian dollar weaken compared to the U.S. dollar. See "Liquidity" and "Capital Resources" above.

REGULATORY APPROVAL RISKS

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

PERFORMANCE

Connacher's financial and operating performance is potentially affected by a number of factors, including, but not limited to the following:

- Connacher's ability to reliably operate its oil sands facilities is important in meeting production targets
- Production and operating expenses could be impacted by inflationary pressures on labor, volatile pricing for natural gas used as an energy source in oil sands processes and planned and unplanned maintenance. The Company continues to address these risks through such strategies as application of technologies and an increased focus on regular preventative maintenance
- Production and operating expenses are also impacted by the introduction of, or increase in, government levies or taxes relating to environmental and Aboriginal matters applicable to oil sands companies
- While fiscal regimes in Alberta, Canada are generally stable relative to many global jurisdictions, royalty and tax treatments are subject to periodic review, the outcome of which is not predictable and could result in changes to the Company's planned investments and rates of return on existing investments
- Extreme volatility in heavy oil differentials and benchmarks on which the Company's contracts are based increases marketing risks and impacts the Company's overall profitability
- There are certain risks associated with the execution of capital projects, including the risk of cost overruns and delays. Numerous risks and uncertainties can affect construction and other capital project schedules, including the availability of labor and other impacts of competing projects drawing on the same resources during the same time period

CAPITAL REQUIREMENTS

As the Company's revenues may decline as a result of decreased production and/or commodity pricing, it may be required to reduce capital expenditures. In addition, uncertain levels of near term industry activity coupled with the global economic situation exposes the Company to additional access to capital risk. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. In the event that the Company does not generate increased EBITDA in future quarters the Company will be unable to fully utilize its available capital available under the Facility. The inability of the Company to access sufficient capital for its operations and growth could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

THIRD PARTY CREDIT RISK

Credit risk is a risk of failure of performance by counterparties. The Company attempts to mitigate this credit risk before contract initiation by ensuring product sales and delivery contracts are made with well–known and financially strong crude oil and natural gas marketers. The Company may be exposed to third party credit risk through its contractual arrangements with its current counterparties. In the event such entities fail to meet their contractual obligations to the Company, such failures may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

ENVIRONMENTAL

All phases of the oil and gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and production and operating expenses. There has been much public debate with respect to Canada's alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases could have a material impact on the nature of oil and gas operations, including those of the Company. Given the evolving nature of the issues related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict either the nature of those requirements or the impact on the Company and its operations and financial condition. The Company may be subject to remedial environmental and litigation costs resulting from potential unknown and unforeseeable environmental impacts arising from the Company's operations. While these costs have not been material to the Company in the past, there is no guarantee that this will continue to be the case in the future as the Company carries on with development of technologies.

The oil sands business is closely regulated with respect to land disturbance, water usage and green house gas emission. To meet these requirements, operations personnel closely follow established environmental policies and procedures and regularly report to regulators.

ACCOUNTING POLICIES AND ESTIMATES

Management makes judgments, estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Although these estimates are based on management's best knowledge of the amount, event or actions, actual results ultimately may differ from those estimates. Accordingly, actual reported amounts may differ from estimated amounts as future confirming events occur.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

There have been no changes to our critical accounting policies and estimates in the first half of 2013. Further information on our critical accounting policies and estimates can be found in the notes to the Consolidated Financial Statements and Annual MD&A for the year ended December 31, 2012.

FUTURE CHANGES IN ACCOUNTING POLICIES

There are no updates to future changes in accounting policies in the first half of 2013. Further information on future changes in accounting policies can be found in the notes to the Consolidated Financial Statements and Annual MD&A for the year ended December 31, 2012.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

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 changes in the Company’s internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company’s internal controls over financial reporting.

ADVISORY SECTION

FORWARD LOOKING INFORMATION

This MD&A contains forward looking information including expectations for future capital expenditures and funding thereof, future well drilling and development activities and the timing of production therefrom, expectations regarding the Company's ability to rely on the debt basket provided for pursuant to the Note Indenture related to the Company's existing Notes, expectations regarding the continued assessment for the SAGD+ commercial project during 2013 and general operational and financial performance in future periods.

Forward looking information is based on management’s expectations regarding the Company's future financial position, the Company's future growth, results of operations and 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 geological interpretations, the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks), risk of commodity price and foreign exchange rate fluctuations, risks associated with the impact of general economic conditions, risks and uncertainties associated with maintaining the necessary regulatory approvals and securing the financing to proceed with the operation and continued expansion of the Great Divide oil sands project.

Information relating to “reserves” are deemed to be forward looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future to achieve the future net revenue calculated in accordance with certain assumptions, the effective. The effective date of the reserves estimate provided herein is December 31, 2012. The assumptions relating to the reserves and associated future net revenues reported herein are contained in the report of GLJ Petroleum Consultants Ltd. for the year ended December 31, 2012 and are summarized in Connacher’s AIF, which is available on SEDAR at www.sedar.com.

In addition, reported average production levels may not be reflective of sustainable production rates and future production rates may differ materially from the production rates reflected in this MD&A due to, among other factors, difficulties or interruptions encountered during the production of bitumen.

Additional risks and uncertainties affecting Connacher and its business and affairs are described in further detail in Connacher’s AIF. 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 MD&A is expressly qualified in its entirety by this cautionary statement. The forward looking information included herein is made as of the date of this MD&A and Connacher assumes no obligation to update or revise any forward looking information to reflect new events or circumstances, except as required by law.

NON–GAAP MEASUREMENTS

The MD&A contains terms commonly used in the oil and gas industry, such as, netback, earnings before interest, taxes, depreciation and amortization ("EBITDA") and funds flow. These terms are not defined by the financial measures used by Connacher to prepare its financial statements and are referred to herein as non–GAAP measures. These non–GAAP measures should not be considered an alternative to, or more meaningful than, cash provided by operating activities or net earnings (loss) as determined in accordance with GAAP as an indicator of Connacher's performance. Management believes that in addition to net earnings (loss), netbacks and EBITDA are useful financial measurements which assist in demonstrating the Company's ability to make interest payments, fund capital expenditures necessary for future growth or to repay debt. Connacher's determination of netbacks, EBITDA and funds flow may not be comparable to that reported by other companies.

NETBACKS

Bitumen netbacks are calculated by deducting the related diluent, transportation, handling, field production and operating expenses and royalties from dilbit sales. Conventional netbacks (Discontinued Operations) are calculated by deducting transportation, handling, field production and operating expenses and royalties from conventional revenues. Refining netbacks (Discontinued Operations) are calculated by deducting crude oil purchases and operating from revenues, and before elimination the intersegment sales and related cost of sales. For a reconciliation of conventional netbacks and refining netbacks for the three months and six months ended 2012, please see the Q2 2012 MD&A which is available at www.sedar.com.

EBITDA FROM CONTINUING OPERATIONS

EBITDA from continuing operations is calculated as net earnings (loss) from operations before finance charges, current and deferred income tax provisions and recoveries, depletion, depreciation and amortization, exploration and evaluation expense, share–based compensation, foreign exchange gains/losses, unrealized gains/losses on risk management contracts, interest and other income, gain (loss) on disposition of assets and refinancing of long–term debt.

FUNDS FLOW FROM CONTINUING OPERATIONS

Funds flow from continuing operations includes all cash flows from operating activities and is calculated before changes in non–cash working capital, decommissioning liabilities settled and after interest expense on long–term debt. The most comparable measure calculated in accordance with GAAP is cash flow from operating activities. Funds flow from operating activities is reconciled with cash flow from continuing operations for the three months and six months ended June 30, 2013 and 2012 below.

RECONCILIATIONS OF NON–GAAP MEASUREMENTS

Cash flow from continuing operations is reconciled to cash flow from operating activities and oil sands netbacks and EBITDA from continuing operations are reconciled to net earnings (loss) herein.

RECONCILIATIONS OF FUNDS FLOW FROM CONTINUING OPERATIONS TO CASH FLOW FROM OPERATING ACTIVITIES

	Three months ended June 30		Six months ended June 30	
($ 000)	**2013**	2012	**2013**	2012
Cash flow (used in) from operating activities – continuing operations	**$21,555**	$18,018	**$29,862**	$40,503
Changes in non–cash working capital	**3,825**	(11,546)	**5,313**	(22,713)
Decommissioning liabilities settled	**2**	12	**143**	772
Interest expense on long–term debt	**(19,704)**	(20,650)	**(39,151)**	(41,209)
Funds flow (used in) from continuing operations	**$5,678**	$(14,166)	**$(3,833)**	$(22,647)
Cash flow from operating activities – Discontinued Operations	**-**	13,526	**-**	(18,466)
Funds flow	**$5,678**	$(640)	**$(3,833)**	$(41,113)

RECONCILIATIONS OF OIL SANDS NETBACKS AND EBITDA FROM CONTINUING OPERATIONS TO NET LOSS

	Three months ended June 30		Six months ended June 30	
($ 000)	**2013**	2012	**2013**	2012
Bitumen netbacks – continuing operations	**$33,960**	$14,904	**$52,710**	$49,490
Realized loss on risk management contracts	**(2,468)**	(1,319)	**(2,926)**	(5,728)
General and administrative expenses	**(7,088)**	(6,629)	**(14,698)**	(24,387)
EBITDA from continuing operations	**$24,404**	$6,956	**$35,086**	$19,375
Interest and other income	**189**	50	**576**	108
Gain (loss) on sale of assets	**2,107**	(419)	**2,009**	6,256
Unrealized gain (loss)on risk management contracts	**2,684**	26,780	**(1,342)**	16,808
Share–based compensation	**(435)**	(343)	**(872)**	(1,017)
Finance charges	**(21,861)**	(23,755)	**(43,659)**	(46,912)
Foreign exchange gain (loss)	**(17,439)**	(9,758)	**(27,290)**	(1,071)
Depletion, depreciation and amortization	**(21,766)**	(19,775)	**(43,153)**	(41,027)
Income tax recovery (provision)	**-**	-	**-**	4,237
Exploration and evaluation expenses	**-**	-	**(38)**	(23)
Net earnings (loss), continuing operations	**$(32,117)**	$(20,264)	**$(78,683)**	$(43,266)

QUARTERLY HIGHLIGHTS

Fluctuations in results over the previous eight quarters are due principally to variations in oil and gas prices, production and sales volumes and foreign exchange rates relative to U.S. dollar denominated debt. Revenue for periods prior to Q4 2012 includes revenue from Discontinued Operations. For comparability, the following table presents the financial information for all of the quarters presented in the same format as was adopted in the quarter ended December 31, 2012.

Three months ended	2011 Sept 30	2011 Dec 31	2012 Mar 31	2012 June 30	2012 Sept 30	2012 Dec 31	2013 Mar 31	**2013 June 30**
FINANCIAL ($000 except per share amounts)								
Total revenue(1)	$232,806	$226,454	$192,818	$205,592	$232,753	$94,990	$101,320	$110,613
Revenue, continuing operations(1)	100,231	119,379	107,747	81,411	100,829	94,959	101,320	110,613
EBITDA, continuing operations (2)(6)	17,929	30,259	12,419	6,956	10,118	11,176	10,682	24,404
Net earnings (loss), continuing operations	(4,591)	(49,075)	(23,001)	(20,264)	(25,379)	(40,527)	(46,566)	(32,117)
Net earnings (loss), discontinued operations	8,233	(10,402)	2,443	(24,798)	13,697	33,360	-	-
Net earnings (loss)	3,642	(59,477)	(20,558)	(45,062)	(11,682)	(7,167)	(46,566)	(32,117)
Basic and Diluted per share, continuing operations	(0.01)	(0.11)	(0.06)	(0.05)	(0.06)	(0.09)	(0.10)	(0.07)
Basic and Diluted per share, total	0.01	(0.13)	(0.05)	(0.10)	(0.03)	(0.02)	(0.10)	(0.07)
Capital expenditures, continuing operations	11,285	32,201	11,856	8,882	4,968	11,423	20,251	28,436
Cash on hand	81,744	117,045	48,852	41,499	39,643	126,844	81,714	76,724
Working capital surplus (deficit)	50,801	16,876	(5,059)	110,555	110,935	111,686	76,957	56,606
Long–term debt	865,540	856,068	848,256	939,623	842,972	849,938	861,828	881,396
Shareholders' equity	$477,358	$421,076	$399,087	$357,742	$340,869	$342,900	$296,746	$265,064
OPERATIONAL								
Average benchmark prices								
WTI (US$/bbl)	89.75	94.06	102.94	93.50	92.22	88.18	94.37	94.27
Heavy oil differential ($/bbl)	17.30	10.70	21.41	23.00	21.65	17.94	32.33	17.13
WCS ($/bbl)	70.68	85.85	81.65	71.31	70.05	69.47	62.87	79.04
Continuing Operation: Daily production volumes (3)								
Bitumen – bbl/d	13,454	13,173	12,429	11,674	11,478	11,945	12,406	11,572
Selected highlights ($/per bbl)								
Dilbit sales	65.15	77.47	74.17	62.01	70.73	69.43	71.12	85.06
Diluent costs	(13.24)	(12.34)	(13.88)	(15.22)	(12.21)	(9.97)	(12.44)	(7.03)
Realized bitumen sales price(5)	51.91	65.13	60.29	46.79	58.52	59.46	58.68	78.03
Transportation and handling costs	(10.92)	(12.09)	(9.69)	(12.48)	(20.40)	(17.91)	(20.37)	(21.65)
	40.99	53.04	50.60	34.31	38.12	41.55	38.31	56.38
Royalties	(2.13)	(3.09)	(2.86)	(2.43)	(2.15)	(2.20)	(2.29)	(3.06)
Production and operating expenses	(18.83)	(19.80)	(17.45)	(17.21)	(20.35)	(21.39)	(19.59)	(21.53)
Bitumen netback (2)(6)	20.03	30.15	30.29	14.67	15.62	17.96	16.43	31.79
Discontinued Operations: Conventional daily volumes								
Crude oil – bbl/d	355	417	359	305	217	12	-	-
Natural gas – Mcf/d	3,036	2,955	2,075	2,139	1,490	-	-	-
Equivalent – boe/d (4)	861	910	705	662	465	12	-	-
Refining								
Refining utilization – %	101	108	106	102	105	-	-	-
Margins – %	14	7	12	18	19	-	-	-

(1) Net of royalties, and eliminating intercompany sales
(2) A non–GAAP measure which is defined in the Advisory section of the MD&A
(3) Represents bitumen, crude oil and natural gas produced in the period. Actual sales volumes may be different due to the inventory at the period end
(4) All references to barrels of oil equivalent (boe) are calculated on the basis of 6 Mcf: 1 bbl. This conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Boe may be misleading, particularly if used in isolation
(5) Before royalties and risk management contract gains or losses and after applicable diluent costs divided by actual sales volumes
(6) Quarterly information is presented in accordance with previous GAAP as reported earlier in the respective financial statements. Reconciliations of EBITDA and Bitumen Netbacks from Continuing Operations to Net Loss are set forth on the following page

RECONCILIATIONS OF OIL SANDS NETBACKS AND EBITDA FROM CONTINUING OPERATIONS TO NET LOSS

Three months ended ($000)	2011 Sept 30	2011 Dec 31	2012 Mar 31	2012 June 30	2012 Sept 30	2012 Dec 31	2013 Mar 31	**2013 June 30**
Bitumen netbacks – continuing operations	$24,819	$36,755	$34,586	$14,904	$17,031	$19,459	$18,750	**$33,960**
Realized loss on risk management contracts	(285)	195	(4,409)	(1,319)	1,283	207	(458)	**(2,468)**
General and administrative expenses	(6,605)	(6,691)	(17,758)	(6,629)	(8,196)	(8,490)	(7,610)	**(7,088)**
EBITDA from continuing operations	$17,929	$30,259	$12,419	$6,956	$10,118	11,176	$10,682	**24,404**
Interest and other income	34	332	58	50	255	83	387	**189**
Gain (loss) on sale of assets	14,825	(19,839)	6,675	(419)	(538)	(332)	(98)	**2,107**
Unrealized gain (loss) on risk management contracts	30,958	(20,327)	(9,972)	26,780	(9,045)	(4,010)	(4,026)	**2,684**
Stock–based compensation	(650)	(687)	(674)	(343)	(253)	(245)	(437)	**(435)**
Finance charges	(15,550)	(30,988)	(23,157)	(23,755)	(22,373)	(21,514)	(21,798)	**(21,861)**
Foreign exchange gain (loss)	(37,227)	10,610	8,687	(9,758)	17,901	(4,479)	(9,851)	**(17,439)**
Depletion, depreciation and amortization	(20,471)	(22,778)	(21,252)	(19,775)	(21,552)	(21,206)	(21,387)	**(21,776)**
Income tax recovery (provision)	3,436	4,312	4,238	-	70	-	-	**-**
Exploration and evaluation expenses	(201)	62	(23)	-	38	-	(38)	**-**
Share of interest in and loss on disposal of associate	-	(12)	-	-	-	-	-	**-**
Cost of refinancing long term debt	2,326	(19)	-	-	-	-	-	**-**
Net earnings (loss), continuing operations	$(4,591)	$(49,075)	$(23,001)	$(20,264)	$(25,379)	$(40,527)	$(46,566)	**$(32,117)**

CONDENSED CONSOLIDATED BALANCE SHEET

(UNAUDITED)

As at (Canadian dollar in thousands)	Notes	June 30, 2013	December 31, 2012
ASSETS			
CURRENT ASSETS			
Cash and cash equivalents		**$76,724**	$126,844
Trade and accrued receivables		**51,873**	50,536
Inventories		**8,777**	9,537
Risk management contracts	7	**5**	2,017
Other assets		**580**	1,273
		137,959	190,207
NON–CURRENT ASSETS			
Other assets		**–**	189
Exploration and evaluation assets	5	**26,411**	26,432
Property, plant and equipment	6	**1,119,307**	1,118,373
		1,145,718	1,144,994
		$1,283,677	$1,335,201
LIABILITIES AND SHAREHOLDERS' EQUITY			
CURRENT LIABILITIES			
Trade and accrued payables		**$77,056**	$77,175
Risk management contracts	7	**4,297**	1,346
		81,353	78,521
NON–CURRENT LIABILITIES			
Long–term debt	9	**881,396**	849,938
Decommissioning liabilities	10	**54,960**	59,317
Risk management contracts	7	**904**	4,525
		937,260	913,780
SHAREHOLDERS' EQUITY			
Share capital	11	**621,847**	621,523
Contributed surplus		**40,078**	39,555
Deficit		**(396,861)**	(318,178)
		265,064	342,900
		$1,283,677	$1,335,201

The accompanying notes to the condensed interim consolidated financial statements are an integral part of these statements.

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE LOSS

(UNAUDITED)

		Three months ended June 30		Six months ended June 30	
(Canadian dollar in thousands, except per share amounts)	Notes	**2013**	2012	**2013**	2012
Continuing Operations					
INCOME					
Revenue, net of royalties	3	**$110,613**	$81,411	**$211,933**	$189,158
Interest and other income		**189**	50	**576**	108
		110,802	81,461	**212,509**	189,266
EXPENSES					
Blending and costs of products sold		**30,515**	35,747	**67,488**	77,920
Production and operating expenses		**23,006**	17,913	**45,357**	37,838
Transportation and handling costs		**23,132**	12,847	**46,378**	23,910
General and administrative		**7,088**	6,629	**14,698**	24,387
Share–based compensation		**435**	343	**872**	1,017
Exploration and evaluation expenses		**–**	-	**38**	23
Depletion, depreciation and amortization		**21,766**	19,775	**43,153**	41,027
(Gain) loss on risk management contracts	7	**(216)**	(25,461)	**4,268**	(11,080)
Finance charges		**21,861**	23,755	**43,659**	46,912
Foreign exchange loss		**17,439**	9,758	**27,290**	1,071
Loss (gain) on disposition of property, plant and equipment		**(2,107)**	419	**(2,009)**	(6,256)
		142,919	101,725	**291,192**	236,769
LOSS BEFORE INCOME TAX FROM CONTINUING OPERATIONS		**(32,117)**	(20,264)	**(78,683)**	(47,503)
Income tax recovery	13	**–**	-	**–**	4,237
NET LOSS FROM CONTINUING OPERATIONS		**(32,117)**	(20,264)	**(78,683)**	(43,266)
Discontinued Operations					
Net loss from discontinued operations	4	**–**	(24,798)	**–**	(22,354)
NET LOSS		**(32,117)**	(45,062)	**(78,683)**	(65,620)
OTHER COMPREHENSIVE INCOME AFTER TAX					
Items recognized in the other comprehensive income:					
Exchange differences on translating foreign operations		**–**	2,958	**–**	703
OTHER COMPREHENSIVE INCOME AFTER TAX		**–**	2,958	**–**	703
TOTAL COMPREHENSIVE LOSS		**$(32,117)**	$(42,104)	**$(78,683)**	$(64,917)
NET LOSS PER SHARE – basic and diluted	11				
From continuing operations		**$(0.07)**	$(0.04)	**$(0.18)**	$(0.10)
From discontinued operations		**–**	(0.06)	**–**	(0.05)
From net loss		**$(0.07)**	$(0.10)	**$(0.18)**	$(0.15)

The accompanying notes to the condensed interim consolidated financial statements are an integral part of these statements.

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(UNAUDITED)

	For the six months ended June 30	
(Canadian dollar in thousands)	**2013**	2012
SHARE CAPITAL		
Balance, beginning of period	**$621,523**	$620,266
Cash received on shares issued upon exercise of stock options	**–**	644
Transfer from contributed surplus – stock options exercised	**–**	288
Transfer from contributed surplus – share awards issued	**324**	325
Balance, end of period	**$621,847**	$621,523
CONTRIBUTED SURPLUS		
Balance, beginning of period	**$39,555**	$38,841
Share–based compensation (2)	**872**	1,072
Transfer to share capital – stock options exercised	**–**	(288)
Transfer to share capital – share awards issued	**(324)**	(325)
Cash paid on settlement of share awards and share units	**(25)**	(133)
Balance, end of period	**$40,078**	$39,167
DEFICIT		
Balance, beginning of period	**$(318,178)**	$(233,709)
Net loss (1)	**(78,683)**	(65,620)
Balance, end of period	**$(396,861)**	$(299,329)
ACCUMULATED OTHER COMPREHENSIVE LOSS		
Balance, beginning of period	**$–**	$(4,322)
Exchange differences on translating foreign operations (1)	**–**	703
Balance, end of period	**$–**	$(3,619)
Total Shareholders' equity	**$265,064**	$357,742

(1) Total comprehensive loss for the six months ended June 30, 2013 is $78.7 million (six months ended June 30, 2012 – $64.9 million)

(2) This includes share based compensation expense of $nil for the six months ended June 30, 2013 (six months ended June 20, 2012: $55,000) recorded in net earnings from discontinued refining operations. Refer to note 4.

The accompanying notes to the condensed interim consolidated financial statements are an integral part of these statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOW

(UNAUDITED)

(Canadian dollar in thousands)	Notes	Three months ended June 30 2013	2012	Six months ended June 30 2013	2012
OPERATING					
Net loss from continuing operations		**$(32,117)**	$(20,264)	**$(78,683)**	$(43,266)
Adjustments for:					
Depletion, depreciation and amortization		**21,766**	19,775	**43,153**	41,027
Share–based compensation		**435**	343	**872**	1,017
Finance charges – non–cash portion		**1,688**	1,606	**3,342**	3,609
Interest expense on long–term debt		**19,704**	20,650	**39,151**	41,209
Deferred income tax recovery	13	**–**	-	**–**	(4,234)
Unrealized (gain) loss on risk management contracts	7	**(2,684)**	(26,780)	**1,342**	(16,808)
Unrealized foreign exchange loss		**18,297**	9,735	**28,150**	1,146
Loss (gain) on disposition of property, plant and equipment		**(2,107)**	419	**(2,009)**	(6,256)
Costs of refinancing long–term debt		**–**	1,000	**–**	1,118
Decommissioning liabilities settled	10	**(2)**	(12)	**(143)**	(772)
Changes in non–cash working capital		**(3,825)**	11,546	**(5,313)**	22,713
Cash flow from operating activities – continuing operations		**21,155**	18,018	**29,862**	40,503
Cash flow from (used in) operating activities – discontinued operations	4	**–**	13,526	**–**	(18,466)
Cash flow from operating activities		**21,155**	31,544	**29,862**	22,037
INVESTING					
Expenditures on property, plant and equipment	6	**(28,436)**	(8,882)	**(47,882)**	(20,198)
Exploration and evaluation expenditures	5	**–**	-	**(805)**	(540)
Proceeds on disposition of assets		**2,128**	-	**2,128**	7,000
Changes in non–cash working capital		**(245)**	(6,254)	**4,325**	(13,593)
Cash flow used in investing activities – continuing operations		**(26,553)**	(15,136)	**(42,234)**	(27,331)
Cash flow used in investing activities – discontinued operations	4	**–**	(2,974)	**–**	(6,320)
Cash flow used in investing activities		**(26,553)**	(18,110)	**(42,234)**	(33,651)
FINANCING					
Proceeds on issue of common shares		**–**	394	**–**	644
Proceeds on issue of long term debt		**–**	80,000	**–**	80,000
Cash paid on settlement of share awards and share units		**–**		**(25)**	(133)
Cash paid on settlement of long–term debt		**–**	(100,014)	**–**	(103,659)
Interest paid on long–term debt		**–**	(2,375)	**(38,686)**	(41,073)
Cash flow used in financing activities		**–**	(21,995)	**(38,711)**	(64,221)
NET DECREASE IN CASH AND CASH EQUIVALENTS		**(5,398)**	(8,561)	**(51,083)**	(75,835)
Foreign exchange gain on cash balances held in foreign currency		**408**	1,208	**963**	289
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD		**81,714**	48,852	**126,844**	117,045
CASH AND CASH EQUIVALENTS, END OF PERIOD		**$76,724**	$41,499	**$76,724**	$41,499

The accompanying notes to the condensed interim consolidated financial statements are an integral part of these statements.

NOTES TO THE CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

1. NATURE OF OPERATIONS

Connacher Oil and Gas Limited ("Connacher" or "the company") is a public company listed on the Toronto Stock Exchange under the symbol CLL and headquartered in Calgary, Alberta, Canada. The address of the company's principal office is Suite 900, 322 – 6th Avenue S.W., Calgary, Alberta. As at June 30, 2013, the company was engaged in the business of exploration, development and production of bitumen.

During the year ended December 31, 2012, the company fully exited the refining business and the conventional petroleum and natural gas business. As a result, the results of the refining and conventional petroleum and natural gas operations are presented as discontinued operations for the six and three months ended June 30, 2012. Refer to note 4 *Discontinued Operations*.

These condensed interim consolidated financial statements ("interim consolidated financial statements") were approved and authorized for issuance by the Board of Directors on August 14, 2013.

2. BASIS OF PREPARATION AND ACCOUNTING POLICIES

These condensed interim consolidated financial statements have been prepared in accordance with International Accounting Standard ("IAS") 34, "Interim Financial Reporting" and follow the same accounting policies and methods of computation as the most recent annual consolidated financial statements, except as noted below on new accounting pronouncements. Certain information and disclosures normally required to be included in notes to the annual consolidated financial statements have been condensed or omitted. Accordingly, these condensed interim consolidated financial statements should be read in conjunction with the annual consolidated financial statements and the notes thereto for the year ended December 31, 2012, which were prepared in accordance with International Financial Reporting Standards ("IFRS").

NEW ACCOUNTING PRONOUNCEMENTS ADOPTED

As of January 1, 2013, the company adopted the following standards and amendments as issued by the IASB. The adoption of the following standards did not have a material impact on the company's condensed interim consolidated financial statements.

IFRS 10 "Consolidated Financial Statements":

IFRS 10 replaces Standing Interpretations Committee 12, "Consolidation - Special Purpose Entities" and the consolidation requirements of IAS 27 "Consolidated and Separate Financial Statements". The new standard replaces the existing risk and rewards based approaches and establishes control as the determining factor when determining whether an interest in another entity should be included in the consolidated financial statements

IFRS 11 "Joint Arrangements":

IFRS 11 replaces IAS 31 "Interests in Joint Ventures". The new standard focuses on the rights and obligations of an arrangement, rather than its legal form. The standard redefines joint operations and joint ventures and requires joint operations to be proportionately consolidated and joint ventures to be equity accounted. This standard has no impact on the company's condensed interim consolidated financial statements.

IFRS 12 "Disclosure of Interests in Other Entities":

IFRS 12 provides comprehensive disclosure requirements on interests in other entities, including joint arrangements, associates, and special purpose entities. The new disclosures are intended to assist financial statement users in evaluating the nature, risks and financial effects of an entity's interest in subsidiaries and joint arrangements. This standard has no impact on the company's condensed interim consolidated financial statements.

IFRS 13 "Fair Value Measurement":

IFRS 13 provides a common definition of fair value within IFRS. The new standard provides measurement and disclosure guidance and applies when another IFRS requires or permits an item to be measured at fair value, with limited exceptions.

IAS 34 "Interim Financial Reporting":

Amendments to IAS 34 require specific disclosure on the fair value of financial instruments for interim reporting. These disclosures are included in Note 8.

3. SEGMENT REPORTING AND SEASONALITY OF OPERATIONS

Management had previously segmented the company's business based on differences in products and services and management responsibility. The company's business was conducted predominantly through two major operating segments – upstream in Canada and downstream in USA, through a wholly-owned subsidiary, Montana Refining Company, Inc. ("MRCI"). Upstream included exploration for and the development and production of bitumen. Downstream included refining of primarily crude oil to produce and market gasoline, jet fuel, diesel fuels, asphalt and ancillary products. During the year ended December 31, 2012 the company discontinued its downstream operations in the USA and sold MRCI effective October 1, 2012 (refer to Note 4).

3.1 SEGMENT REVENUE AND RESULTS

Performance was measured based on segment operating income. This measure excluded interest and other income, gain (loss) on disposition of assets, unrealized gain (loss) on risk management contracts, share-based compensation, employee benefit plan expense, finance charges, foreign exchange gain (loss), depletion, depreciation, amortization and impairment, exploration and evaluation expenses and costs associated with long-term debt.

The downstream operating segment has been disposed of and is presented as a discontinued operation. Refer to note 4 for information regarding revenue, results and assets of the downstream segment. The continuing operations in the consolidated statements of operations and comprehensive loss only relate to the upstream segment. Therefore segmented reporting is no longer required.

4. DISCONTINUED OPERATIONS

During the year ended December 31, 2012, the company fully exited the refining business and the conventional petroleum and natural gas business. Results of the refining and conventional petroleum and natural gas operations are presented as discontinued operations for the prior period.

The following table summarizes the analysis of the results of discontinued **refining operations**:

	Three months ended June 30		Six months ended June 30	
(Canadian dollar in thousands)	**2013**	2012	**2013**	2012
INCOME				
Revenue(1)	$–	$126,706	$–	$214,242
Interest and other income	–	35	–	112
	–	126,741	–	214,354
EXPENSES				
Blending and costs of products sold	–	94,575	–	162,663
Production and operating expenses	–	6,116	–	14,106
Transportation and handling costs	–	2,982	–	4,128
General and administrative	–	1,495	–	3,396
Share based compensation	–	22	–	55
Depletion, depreciation and amortization	–	2,350	–	4,977
Finance charges	–	7	–	13
Foreign exchange gain	–	40	–	(32)
	–	107,587	–	189,306
Earnings before tax from discontinued refining operations	–	19,154	–	25,048
Income tax provision (note 13)	–	(6,686)	–	(8,375)
Net earnings from discontinued refining operations	$–	$12,468	$–	16,673

(1) Includes intersegment revenue of $9.3 million in the six months ended June 30, 2012 (three months ended June 30, 2012: $4.3 million). This intersegment revenue was transacted at prevailing market prices.

The following table summarizes the analysis of the results of discontinued **conventional petroleum and natural gas operations**:

	Three months ended June 30		Six months ended June 30	
(Canadian dollar in thousands)	**2013**	2012	**2013**	2012
INCOME				
Revenue, net of royalties	$–	$1,760	$–	$4,305
EXPENSES				
Production and operating expenses	–	1,128	–	2,718
Transportation and handling costs	–	73	–	185
Depletion, depreciation, amortization and impairment	–	37,816	–	40,429
	–	39,017	–	43,332
Loss before tax from discontinued operations	–	(37,257)	–	(39,027)
Income tax provision	–	–	–	–
Loss after tax from discontinued operations	–	(37,257)	–	(39,027)
Loss on disposition of assets	–	(9)	–	-
Net loss from discontinued conventional petroleum and natural gas operations	$–	$(37,266)	$–	$(39,027)
Net loss from discontinued operations	$–	$(24,798)	$–	$(22,354)

The following table summarizes the components of the **discontinued refining operations** cash flows:

	Three months ended June 30		Six months ended June 30	
(Canadian dollar in thousands)	**2013**	2012	**2013**	2012
Cash flow from (used in) operating activities	$–	$12,967	$–	$(19,868)
Cash flow used in investing activities	–	(2,831)	–	(6,190)
Total cash inflow (outflow)	$–	$10,136	$–	$(26,058)

The following table summarizes the components of the **discontinued conventional petroleum and natural gas operations** cash flows:

	Three months ended June 30		Six months ended June 30	
(Canadian dollar in thousands)	**2013**	2012	**2013**	2012
Cash flow from operating activities	$–	$559	$–	$1,402
Cash flow used in investing activities	–	(143)	–	(130)
Total cash inflow	$–	$416	$–	1,272

The following table summarizes the components of the **total discontinued operations** cash flows:

	Three months ended June 30		Six months ended June 30	
(Canadian dollar in thousands)	**2013**	2012	**2013**	2012
Cash flow from (used in) operating activities	$–	$13,526	$–	$(18,466)
Cash flow used in investing activities	–	(2,974)	–	(6,320)
Total cash inflow (outflow)	$–	$10,552	$–	$(24,786)

5. EXPLORATION AND EVALUATION ASSETS ("E&E")

(Canadian dollar in thousands)	
Cost	
Balance, December 31, 2012	$44,990
Additions	805
Transfer to Property, plant and equipment	(805)
Balance, June 30, 2013	**$44,990**
Accumulated amortization and impairment	
Balance, December 31, 2012	$18,558
Amortization charge for the period	21
Balance, June 30, 2013	**$18,579**
Carrying amount	
As at June 30, 2013	**$26,411**
As at December 31, 2012	$26,432

As at June 30, 2013, E&E assets represent the company's oil sands evaluation projects which are pending the determination of technical feasibility and commercial viability.

6. PROPERTY, PLANT AND EQUIPMENT

(Canadian dollar in thousands)	Oil sands	Corporate	Total
Cost			
Balance, December 31, 2012	$1,324,493	$16,551	$1,341,044
Additions	47,309	573	47,882
Transfer from E&E assets	805	–	805
Dispositions	(1,379)	(15)	(1,394)
Change in decommissioning liabilities (note 10)	(4,803)	–	(4,803)
Balance, June 30, 2013	**$1,366,425**	**$17,109**	**$1,383,534**
Accumulated depletion, depreciation and impairment			
Balance, December 31, 2012	$211,218	$11,453	$222,671
Depletion and depreciation	41,958	803	42,761
Disposition	(1,205)	–	(1,205)
Balance, June 30, 2013	**$251,971**	**$12,256**	**$264,227**
Carrying value			
As at June 30, 2013	**$1,114,454**	**$4,853**	**$1,119,307**
As at December 31, 2012	$1,113,275	$5,098	$1,118,373

7. RISK MANAGEMENT CONTRACTS

The following table summarizes the net position of the company's risk management contracts:

As at (Canadian dollar in thousands)	**June 30, 2013**	December 31, 2012
Current assets		
Crude oil contracts	**$5**	$1,940
Foreign exchange contracts	**–**	77
Current assets	**$5**	$2,017
Current liabilities		
Crude oil contracts	**$153**	$1,346
Foreign exchange contracts	**4,144**	–
Current liabilities	**$4,297**	$1,346
Non–current liabilities		
Crude oil contracts	**$904**	$4,525
Non–current liabilities	**$904**	$4,525

The following tables summarize the details of the risk management contract positions outstanding as at June 30, 2013 and December 31, 2012:

Crude oil contracts

Term	**Volume range (bbl/d)**	**Price (WTI $/bbl)**	**Liability (Asset)** (Canadian dollar in thousands)	
			June 30, 2013	December 31, 2012
WTI Collars and swaps:				
Jan – Mar 2013	500 – 1,200	US$ 81.88 – US$ 102.51	**$–**	$(12)
Jan – Jun 2013	500	US$ 97.40	**–**	(399)
Jan – Dec 2013	300 – 1,000	US$ 88.48 – US$ 102.51	**(191)**	(1,702)
Apr –Jun 2013	500 – 1,200	US$ 82.22 – US$ 102.37	**–**	56
Apr – Dec 2013	500	US $99.25	**(398)**	(786)
Jul – Sep 2013	1,000	US$ 85.00 – US$ 104.25	**(1)**	(98)
Jul – Dec 2013	250 - 500	US$ 93.27 – US$ 99.56	**(589)**	(751)
Oct – Dec 2013	1,000	US$ 91.58	**248**	–
Jan – Mar 2014	1500	US$ 90.08	**184**	–
April – Jun 2014	500	US$ 90.00	**(30)**	–
Jul – Sep 2014	500	US$90.00	**(207)**	–
Oct – Dec 2014	500	US$90.00	**(188)**	–
WTI Swaptions[(1)]:				
Jul 2013 – June 2014	500	US $97.40 and US$ 99.50	**–**	1,778
Jan 2014 – Dec 2014	375 – 800	US$ 95.00, US$ 97.50, US$ 99.50, US$ 100	**2,224**	5,845
Total liability			**$1,052**	$3,931
Less: current portion – (liability)			**(153)**	(1,346)
Less: current portion – asset			**5**	1,940
Non–current liability			**$904**	$4,525

(1) These are options granting the counterparty the right but not the obligation to enter into underlying swaps on the last business day prior to the contract start date.

Foreign currency contracts

Monthly amount	Term	Type	Contract rate	Liability (Asset) (Canadian dollar in thousands)	
				June 30, 2013	December 31, 2012
$23,463,180	January 2013	FX forward	$1.0027	**$–**	$169
US$5,000,000	Feb 2013 – Jan 2014	FX forward	US$ 0.99	**2,257**	–
US$5,000,000	Feb 2013 – Feb 2014	FX forward	US$ 1.0005	**1,887**	–
US$5,000,000	Feb 2013 – Jun 2013	FX forward	US$ 1.0065	**–**	(246)
Current liabilities (assets)				**$4,144**	$(77)

Subsequent to June 30, 2013, the company entered into the following additional risk management contracts:

Term	**Volume (bbl/d)**	**Price (WTI/bbl)**
<u>WTI Swaps:</u>		
August 2013 - September 2013	1500	CA$107.48
August 2013 - December 2013	500	US$96.03
October 2013 - December 2013	1000	CA$103.15
October 2013 - December 2013	600	US$95.00
January 2014 - March 2014	200	CA$100.00
April 2014 - June 2014	1200	US$95.00
July 2014 - December 2014	1700	US$95.00
<u>Collars:</u>		
January 2014 - December 2014	500	CA$90.00-102.75
January 2014 - June 2014	500	US$85.00-99.00
January 2014 - December 2014	1000	CA90.00-103.00
<u>Swaptions:</u>		
January 2015 – December 2015	700	US$95.00
January 2015 – December 2015	1000	US$95.00

The following tables summarize the amounts recorded in the interim consolidated statements of operations with respect to the risk management contracts. All risk management contracts are entered into at the corporate level, including the expired contracts to obtain fixed refined product pricing. As such, the impacts are included in the net loss from continuing operations:

For the three months ended June 30	**2013**	2012		
(Canadian dollar in thousands)	**Total**	Upstream	Downstream (Discontinued Operations)	Total
Unrealized gain	**$(2,684)**	$(25,460)	$(1,320)	$(26,780)
Realized loss	**2,468**	736	583	1,319
Gain on risk management contracts	**$(216)**	$(24,724)	$(737)	$(25,461)

For the six months ended June 30	2013	2012		
(Canadian dollar in thousands)	**Total**	Upstream	Downstream (Discontinued Operations)	Total
Unrealized loss (gain)	**$1,342**	$(22,400)	$5,592	$(16,808)
Realized loss	**2,926**	5,583	145	5,728
Loss (gain) on risk management contracts	**$4,268**	$(16,817)	$5,737	$(11,080)

8. FAIR VALUE OF FINANCIAL INSTRUMENTS

The risks with respect to financial instruments are consistent with those disclosed in the December 31, 2012 consolidated financial statements. The valuation approach is consistent and there have been no changes in the classification of these financial instruments. The following table shows the comparison of the carrying and fair values of the company's financial instruments:

As at	June 30, 2013		December 31, 2012	
(Canadian dollar in thousands)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Loans and receivables				
Cash and cash equivalents (1)	**$76,724**	**$76,724**	$126,844	$126,844
Trade and accrued receivables (1)	**51,873**	**51,873**	50,536	50,536
Fair value through profit and loss ("FVTPL")				
Risk management contracts - current assets (2)	**5**	**5**	2,017	2,017
Risk management contracts - current liabilities (2)	**4,297**	**4,297**	1,346	1,346
Risk management contracts – non-current liabilities (2)	**904**	**904**	4,525	4,525
Other liabilities				
Trade and accrued payables (1)	**77,056**	**77,056**	77,175	77,175
Long–term debt (3)	**$881,396**	**$517,284**	$849,938	$604,621

(1) The fair values of cash and cash equivalents, trade and accrued receivables and trade and accrued payables approximate their carrying amounts due to the short–term maturity of those instruments

(2) The fair values of the risk management contracts liabilities were derived from observable market prices or indices, a Level 2 measurement. There are no other financial instruments that are classified as either Level 1 or Level 3.

(3) The fair values of long–term debt have been determined based on market information.

9. LONG–TERM DEBT

	Face Value of Principal (millions)	Maturity Date	Interest rate per annum	Interest Payment Terms	Principal Payment Terms	June 30, 2013 (Canadian dollar in thousands)	December 31, 2012 (Canadian dollar in thousands)
Second Lien Senior Notes (Secured)	US$550	Aug 1, 2019	8.50%	Semi–annually on Feb 1 and Aug 1	One payment on maturity	**$578,160**	$547,195
Second Lien Senior Notes (Secured)	$350	Aug 1, 2018	8.75%	Semi–annually on Feb 1 and Aug 1	One payment on maturity	**350,000**	350,000
Total						**928,160**	897,195
Unamortized discount and transaction costs						**(46,764)**	(47,257)
Long–term debt						**$881,396**	$849,938

There were no changes to the terms and conditions of the long–term debt during the six month period ended June 30, 2013. The company was in compliance with all covenants under the long–term debt agreements on June 30, 2013.

10. DECOMMISSIONING LIABILITIES

The following table summarizes the details of decommissioning liabilities:

(Canadian dollar in thousands)	**Six months ended June 30, 2013**	Year ended December 31, 2012
Balance, beginning of period	**$59,317**	$66,078
Liabilities acquired	**1,454**	–
Liabilities settled	**(143)**	(762)
Liabilities disposed	–	(6,722)
Change in estimates	**(6,257)**	(573)
Unwinding of discount	**589**	1,296
Balance, end of period	**$54,960**	$59,317

11. SHARE CAPITAL

Authorized: unlimited number of common voting shares with no par value

Authorized: unlimited number of first preferred shares with no par value of which none are outstanding

Authorized: unlimited number of second preferred shares with no par value of which none are outstanding

11.1 ISSUED AND OUTSTANDING COMMON SHARE CAPITAL

	Six months ended June 30, 2013		Year ended December 31, 2012	
	Number	**Canadian dollars in thousands**	Number	Canadian dollars in thousands
Balance, beginning of period	**449,342,389**	**$621,523**	448,259,991	$620,266
Shares issued upon exercise of stock options	**–**	**–**	907,167	644
Transfer from contributed surplus – stock options	**–**	**–**	–	288
Transfer from contributed surplus – share awards	**377,403**	**324**	238,650	325
Shares returned to treasury	**–**	**–**	(63,419)	–
Balance, end of period	**449,719,792**	**$621,847**	449,342,389	$621,523

The following table summarizes the weighted average common shares outstanding basic and diluted:

	Three months ended June 30		Six months ended June 30	
	2013	2012	**2013**	2012
Weighted average common shares outstanding basic and diluted	**449,719,792**	449,366,978	**449,525,030**	448,710,929

For the three and six month periods ended June 30, 2013 and 2012, any conversion effect of stock options, share award incentives and share units was anti-dilutive and has been excluded from the calculation of diluted income per share.

12. STOCK OPTION PLAN, SHARE AWARD INCENTIVE PLAN AND SHARE UNIT PLAN

There were no changes to the terms and conditions of any share–based compensation plans in the six months ended June 30, 2013.

12.1 STOCK OPTION PLAN

The following table summarizes the changes in stock options and the related weighted average exercise prices:

For the six months ended June 30	**2013**		2012	
	Number of Options	**Weighted Average Exercise Price**	Number of Options	Weighted Average Exercise Price
Outstanding, beginning of period	**18,788,204**	**$0.90**	25,073,735	$1.41
Granted	**4,479,535**	**0.14**	664,474	0.93
Exercised	**–**	**–**	(907,167)	0.71
Forfeited	**(3,821,632)**	**1.00**	(5,954,960)	1.44
Expired	**(90,823)**	**3.07**	(1,463,226)	3.87
Outstanding, end of period	**19,355,284**	**$0.70**	17,412,856	$1.22
Exercisable, end of period	**8,411,810**	**$1.18**	13,035,117	$1.25

At the date of grant, the weighted average fair value of stock options granted during the six months ended June 30, 2013 was $0.08 (six months ended June 30, 2012 – $0.45). The fair value of stock options granted was estimated on the date of grant using the Black–Scholes option pricing model using the following weighted average assumptions:

For the six months ended June 30	**2013**	2012
Weighted average share and exercise price ($ per share)	**0.14**	0.93
Risk free interest rate (percent)	**1.1**	1.3
Expected option life (year)	**3.0**	3.0
Expected volatility (percent)	**89.9**	74.0
Dividend yield (percent)	**0.0**	0.0
Forfeiture rate (percent)	**10.6**	8.4

The expected volatility measured at the standard deviation of continuously compounded share returns was based on statistical analysis of the daily share prices over the last two years (June 30, 2012 : two years).

12.2 SHARE AWARD INCENTIVE PLAN

The following table summarizes the changes in share unit awards:

For the six months ended June 30	**2013**	2012
Outstanding, beginning of period	**494,190**	312,500
Granted	**2,725,000**	494,190
Vested and settled by issuing common shares	**(377,403)**	(238,650)
Vested and settled in cash[(1)]	**(116,787)**	(73,850)
Outstanding, end of period	**2,725,000**	494,190

(1)In satisfaction of withholding tax requirements.

The estimated fair value of each award granted under the Share Award Incentive Plan was $0.20 (six months ended June 30, 2012: $0.86), which is equal to the share price at the date of the grant. The outstanding awards of 2,725,000 as at June 30, 2013 vest in January 2014.

12.3 SHARE UNIT PLAN

The following table summarizes the changes in share units:

For the six months ended June 30	**2013**	2012
Outstanding, beginning of period	**1,689,384**	589,444
Granted	**200,000**	–
Vested and settled in cash	**–**	(101,500)
Forfeited	**(191,698)**	(50,940)
Outstanding, end of period	**1,697,686**	437,004
Vested and exercisable, end of period	**–**	–

13. INCOME TAXES

Income tax recovery recognized in net loss from **continuing** operations:

	Three months ended June 30		Six months ended June 30	
(Canadian dollar in thousands)	**2013**	2012	**2013**	2012
Current tax recovery	**$–**	$–	**$–**	$3
Deferred tax recovery	**–**	–	**–**	4,234
Income tax recovery from continuing operations	**$–**	$–	**$–**	$4,237

Income tax provision recognized in net earnings from **discontinued Refining operations:**

	Three months ended June 30		Six months ended June 30	
(Canadian dollar in thousands)	**2013**	2012	**2013**	2012
Current tax provision	**$–**	$(5,919)	**$–**	$(6,919)
Deferred tax provision	**–**	(767)	**–**	(1,456)
Income tax provision from discontinued operations	**$–**	$(6,686)	**$–**	$(8,375)

14. COMMITMENTS

In addition to the commitments as at December 31, 2012, the company is contractually committed under certain contracts for the service and maintenance of facilities and equipment as at June 30, 2013. The following table provides the details of these additional commitments:

(Canadian dollar in thousands)	**Additional commitments in the six months ended June 30, 2013**
No later than 1 year	$614
Later than 1 year but no later than 5 years	2,991
Later than 5 years	91
Total additional commitments	$3,696

The primary service and maintenance commitment of the company included above relates to railcar contracts up to $2.6 million, incurred in the period ended June 30, 2013, in addition to the railcar costs commitments that exist as at December 31, 2012.