MANAGEMENT DISCUSSION AND ANALYSIS

SUMMARY OF FINANCIAL AND OPERATIONAL RESULTS			
	Three Months Ended March 31		
(000'S Cdn. $ except per share amounts)	**2014**	**2013**	% Change
FINANCIAL			
Oil and gas revenue	**27,606**	21,117	**31**
Funds from operations	**11,053**	7,139	**55**
Per share - basic	**0.69**	0.46	**50**
Per share - diluted	**0.69**	0.45	**52**
Net income (loss)	**1,028**	(4,648)	**-**
Per share - basic	**0.06**	(0.30)	**-**
Per share - diluted	**0.06**	(0.30)	**-**
Total debt	**74,294**	70,641	**5**
Capital expenditures	**12,189**	11,578	**5**
Property acquisitions	**152**	-	**-**
Shares outstanding - end of period (000+A17's)	**16,090**	15,694	**3**
Net wells drilled			
Oil	**4.61**	2.83	**63**
OPERATIONAL			
Daily production			
Heavy oil (bbl/d)	**46**	63	**(26)**
Medium oil and NGL's (bbl/d)	**1,635**	1,425	**15**
Light oil and NGLs (bbl/d)	**1,298**	1,292	**-**
Natural gas (mcf/d)	**6,776**	6,153	**10**
Oil equivalent (boe/d @ 6:1)	**4,108**	3,806	**8**
Realized commodity prices ($Cdn.)			
Heavy oil (bbl)	**71.70**	58.07	**23**
Medium oil and NGL's (bbl)	**86.09**	69.63	**24**
Light oil and NGLs (bbl)	**96.60**	88.31	**9**
Natural gas (mcf)	**5.51**	2.86	**92**
Oil equivalent (boe @ 6:1)	**74.66**	61.65	**21**
Netback ($ per boe)			
Revenue	**74.66**	61.65	**21**
Royalty	**(14.66)**	(13.35)	**10**
Operating cost	**(21.29)**	(22.10)	**(4)**
Operating netback per boe	**38.71**	26.20	**48**
General and administrative	**(2.67)**	(3.19)	**(16)**
Finance expenses	**(1.79)**	(2.08)	**(14)**
Realized loss on risk management contracts	**(4.18)**	(0.06)	**-**
Other (FX and current tax)	**(0.17)**	(0.02)	**673**
Fund from operations per Boe	**29.89**	20.84	**43**

Q1 2014 Financial and Operational Highlights

Dividends

On May 5, 2014, the Board of Directors declared an increase (8.3%) in the quarterly dividend to $0.065 per common share payable May 30, 2014 to shareholders of record on May 16, 2014. The dividend is expected to return approximately $1,044,889 to shareholders.

On February 10, 2014, the Board of Directors declared a quarterly dividend of $0.06 per common share, returning $965,407 to shareholders.

Funds From Operations

Funds from operations Of $11.1 million in Q1 2014 increased 23% from $9.0 million in Q4 2013 and 55% from $7.3 million in Q1. Due to higher production and a strong pricing environment, operating margins increased to $38.71 per Boe in Q1 2014 from $30.20 per Boe in Q4 2013 and $26.20 per Boe in Q1 2013. Cash netback increased to $29.89 per Boe in Q1 2014 from $24.20 per Boe in Q4 2013 and from $20.84 in Q1 2013.

Production

Production for Q1 2014 averaged 4,108 Boe per day (73% crude oil and NGL's and 27% natural gas) versus 4,048 Boe per day in Q4 2013 (75% crude oil and NGL's and 25% natural gas) and 3,806 Boe per day in Q1 2013 (73% crude oil and NGL's and 27% natural gas). Average production was up from Q4 2013 due to new production from recently drilled wells at Princess, Alberta and up from Q1 2013 due to successful drilling at Princess, Alberta and in North Dakota. During Q1 2014, a number of wells in Canada were shut-in for facility expansion and in the US offsetting wells being completed. In addition, a number of wells in both Canada and the US were down due to inclement weather. Production should increase as these operational issues are rectified and as new North Dakota wells drilled in Q1 2014 are completed and are brought on production.

During the quarter the Company drilled two 100% working interest wells in Princess, Alberta and nine gross (2.61 net) wells targeting the Bakken formation at Stanley, North Dakota. One Princess, Alberta well came on production in early March and has averaged 280 Boe per day (97% oil) for the 40 days since it came on production. The second well came on production mid March and has averaged 585 Boe per day (95% oil) for the 48 days since it came on production. Due to spring breakup, the North Dakota wells will not be completed until Q2 2014 and are expected to be on production late in Q2 2014 or in early Q3 2014.

Total Debt

Total debt at March 31, 2014 was $74.3 million, up from $70.4 million at December 31, 2013 and from $70.6 million at March 31, 2013. Debt has increased from December 31, 2013 due higher capital expenditures particularly in North Dakota and an increase in the liability related to the cash settlement of stock options and from March 31, 2013 due to the inclusion in current liabilities of $1.0 million of decommissioning liabilities and the recognition of a current liability related to the cash settlement of stock options . The Company's syndicated credit facility is $90.0 million and is subject to a semi-annual review by May 31, 2014. It is expected that the facility will be renewed at the current level with all terms remaining substantially unchanged.

Capital Expenditures

Capital expenditures (property, plant and equipment and exploration and evaluation) in Q1 2014 totaled $12.2 million versus $11.6 million for Q1 2013. Capital expenditures in Canada were incurred to drill two net wells at Princess. In addition, the Company completed a small property acquisition at Columbia. In the US, capital expenditures were incurred to drill 2.61 net Stanley Bakken wells.

Normal Course Issuer Bid ("NCIB")

On March 27, 2014, the Company announced its intention to make a NCIB to commence April 1, 2014 and ending on March 31, 2015. A total of 804,506 common shares may be acquired under the NCIB, representing 5% of the 16,090,119 common shares outstanding as of March 26, 2014. To date, the Company has acquired 19,900 common shares under the bid at an average cost of $6.82 per share plus expenses.

Corporate Information

As of May 5, 2014, Arsenal has 16,075,219 common shares and 1,228,667 stock options outstanding. The Company's shares are listed and posted for trading on the Toronto Stock Exchange under the symbol "AEI" and in the US over the counter on the pink sheets OTC Pink under the symbol "AEYIF".

In Canada, the Company operates under Arsenal Energy Inc. and had average production 2,741 Boe per day for Q1 2014. In the US, the Company operates under its 100% owned subsidiary Arsenal Energy USA Inc. and had average production 1,367 Boe per day for Q1 2014.

Basis of Presentation

The following is management's discussion and analysis ("MD&A") of Arsenal Energy Inc.'s ("Arsenal" or the "Company") unaudited operating and financial results for the three months ended March 31, 2014. It should be read in conjunction with the audited consolidated financial statements and related notes of the Company for the year ended December 31, 2013. Additional information regarding Arsenal's AIF and financial and operating results may be obtained on the internet at www.sedar.com.

Unless otherwise specified, all dollar amounts are stated in Canadian dollars, and all references to "dollars" or "$" are to Canadian dollars.

The abbreviation "US" relates to the United States.

Tables may not add due to rounding.

Certain prior period amounts may have been reclassified to conform to the current period's presentation.

This MD&A is dated May 5, 2014.

Forward-Looking Statements

Certain statements contained within the Management's Discussion and Analysis constitute forward looking statements. These statements relate to future events or future performance. All statements other than statements of historical fact may be forward looking statements. Forward looking statements are often, but not always, identified by the use of words such as 'seek', 'anticipate', 'budget', 'plan', 'continue', 'estimate', 'expect', 'forecast', 'may', 'will', 'propose', 'project', 'predict', 'potential', 'targeting', 'intend', 'could', 'might', 'should', 'believe' and similar expressions or the negative of these terms or other comparable terminology and are generally intended to identify forward looking statements. These statements involve known and unknown risks, certainties and uncertainties and other factors that may cause actual results or events to differ materially from those anticipated or expected in such forward looking statements.

With respect to the forward-looking statements contained in the MD&A, Arsenal has made assumptions regarding: future commodity prices; the impact of royalty regimes and certain royalty incentives; the timing and the amount of capital expenditures; production of new and existing wells and the timing of new wells coming on-stream; future proved finding and development costs; future operating expenses including processing and gathering fees; the performance characteristics of oil and natural gas properties; the size of oil and natural gas reserves; the ability to raise capital and to continually add to reserves through exploration and development; the continued availability of capital, undeveloped land and skilled personnel; the ability to obtain equipment in a timely manner to carry out exploration and development activities; the ability to obtain financing on acceptable terms; the ability to add production through exploration and development activities; and the continuation of the current tax and regulation regimes.

We believe the expectations reflected in those forward looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward looking statements included in this MD&A should not be unduly relied upon. These statements speak only as of the date of this MD&A. The actual results could differ materially from those anticipated in these forward looking statements as a result of the risk factors set forth below and elsewhere in this MD&A: volatility in market prices for oil and natural gas; counterparty credit risk; access to capital; changes or fluctuations in production levels; liabilities inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; stock market volatility and market valuation of Arsenal stock; geological, technical, drilling and processing problems; limitations on insurance; changes in environmental or legislation applicable to our operations, and our ability to comply with current and future environmental and other laws; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; and the other factors discussed under “Risk Factors” in the MD&A for the year ended December 31, 2013. Readers are cautioned that the foregoing lists of factors are not exhaustive. Additional information on these and other factors that could affect the Company’s operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website. The forward looking statements contained in this MD&A are expressly qualified by this cautionary statement. The forward-looking statements contained in this document speak only as of the date of this document and Arsenal does not assume any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable securities laws.

Boe Presentation

For the purpose of calculating unit costs, natural gas is converted to a barrel of oil equivalent (“Boe” or “boe”) using six thousand cubic feet (“Mcf”) of natural gas to one barrel of oil equivalent unless otherwise stated. Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of six Mcf to one barrel of oil equivalent is based on an energy equivalency method primarily at the burner tip and does not represent a value equivalency at the wellhead. (This conversion conforms to National Instrument 51-101). References to natural gas liquids (“NGLs”) in this MD&A include condensate, propane, butane and ethane and one barrel of NGLs is considered to be equivalent to one barrel of crude oil equivalent (Boe).

Non-GAAP Measures

Within the MD&A, references are made to terms having widespread use in the oil and gas industry in Canada. The measures discussed are widely accepted measures of performance and value within the industry, and are used by investors and analysts to compare and evaluate oil and gas exploration and producing entities.

“Funds from operations”, “Funds from operations per share”, “Operating netbacks per unit or per Boe”, “Netbacks per unit or per Boe”, “Net debt”, “Total debt” or “Bank debt” are not defined by IFRS in Canada and are regarded as non-GAAP measures.

Operating (or field) netback equals total revenue less royalties and operating costs (that include transportation) calculated on a commodity and Boe basis. Boe production per day is calculated by dividing total production for the year or quarter by the number of days in the year or quarter as the case may be. Funds from operations netback is operating netback plus or minus realized gains or losses on commodity contracts and on foreign exchange transactions less cash expenses for general and administrative, interest and other financing charges current income tax and other cash expenses calculated on a Boe basis.

Total debt is defined as bank borrowings plus working capital (excess or deficiency) but excludes the value of risk management contracts whether current or long term and whether an asset or a liability.

Funds from Operations

Funds from operations is not recognized by IFRS but it is used by investors, analysts, bankers and others to evaluate and compare oil and gas exploration and producing entities. Funds from operations are determined as net cash from operating activities before the change in non-cash operating working capital, exploration and evaluation expenses, transaction costs and decommissioning obligations settled. The Company's banker uses funds from operations (adjusted for interest and other financing charges) to measure debt (as defined under the credit facility) to funds flow ratios that determine interest costs to the Company under its credit facility. Funds from operations are used to analyze the Company's performance, the ability of the business to generate the cash flow necessary to fund growth through capital investment and to repay bank debt. Funds from operations should not be considered as an alternative to, or more meaningful than net cash from operating activities as determined in accordance with IFRS as an indicator of the Company's performance. The Company's determination of funds from operations may not be comparable to that reported by other companies. Funds from operations per share basic is calculated based on the weighted average number of common shares outstanding consistent with the calculation of earnings per share. Funds from operations per diluted share is calculated based on the weighted average number of common shares outstanding adjusted for dilutive instruments which in the Company's case are stock options.

The following tables reconcile net cash from operating activities to funds from operations, compare funds from operations by country and funds from operations netback by country per Boe for Q1 2014 to Q1 2013. These numbers are referred to in the MD&A:

Funds from Operations	**Three Months Ended March 31**		
(000's Cdn. $)	**2014**	2013	% Change
Net cash from operating activities	**7,629**	8,651	(12)
Exploration and evaluation expenses	**644**	55	1,067
Transaction costs	**-**	201	-
Decommissioning obligations settled	**234**	51	359
Change in non-cash working capital	**2,546**	(1,820)	(240)
Funds from operations	**11,053**	7,139	55

Funds From Operations By Country	**Three Months Ended March 31**		
(000's Cdn. $)	**2014**	2013	% Change
Canada	**6,137**	2,227	176
US	**4,917**	4,912	-
Funds from operations	**11,053**	7,139	55

Funds From Operations Per Boe	**Three Months Ended March 31**		
($Cdn.)	**2014**	2013	% Change
Canada	**24.87**	10.13	146
US	**39.96**	40.04	-
Total	**29.89**	20.84	43

For Q1 2014, funds from operations totaled $11.1 million or $29.89 per Boe versus $7.1 million or $20.84 per Boe in Q1 2013. The operating netback in Q1 2014 was $38.71 per Boe versus $26.20 per Boe in Q1 2013. The average price received increased by $13.01 per Boe. Royalties increased by $1.31 per Boe and operating costs decreased by $0.81 per Boe. The funds from operations netback in Q1 2014 included a realized loss on commodity contracts of $1.5 million or $4.18 per Boe versus a realized loss of $22,259 or $0.06 per Boe in Q1 2013.

The following tables show quarterly production and compares funds from operations by country and funds from operations and funds from operations per Boe both before and after the effect of commodity contracts for the past eight quarters.

Production	**2014**	2013				2012		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Oil and NGL's (bbls/d)	**2,979**	3,046	3,236	2,729	2,781	3,020	2,808	2,583
Natural gas (mcf/d)	**6,776**	6,012	6,523	5,868	6,153	5,483	5,319	5,837
Total Boe	**369,746**	372,410	397,702	337,311	342,562	361,886	339,816	323,485
Boe per day	**4,108**	4,048	4,323	3,707	3,806	3,934	3,694	3,555

Production By Country	**2014**	2013				2012		
(Boe per day)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Canada	**2,741**	2,332	2,461	2,318	2,443	2,452	2,274	2,443
US	**1,367**	1,716	1,862	1,389	1,363	1,482	1,420	1,112
Total	**4,108**	4,048	4,323	3,707	3,806	3,934	3,694	3,555

Funds From Operations By Country	**2014**	2013				2012		
(000's Cdn. $)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Canada	**6,137**	2,871	2,294	4,378	2,227	4,795	2,431	2,630
US	**4,916**	6,142	9,401	5,633	4,912	5,205	5,351	3,908
Total	**11,053**	9,013	11,695	10,011	7,139	10,000	7,782	6,538

Funds From Operations Per Boe	**2014**	2013				2012		
(Cdn. $)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Canada	**24.87**	13.39	10.13	20.75	10.13	21.26	11.63	11.83
US	**39.96**	38.90	54.88	44.58	40.04	38.19	40.95	38.61
Total	**29.89**	24.20	29.41	29.68	20.84	27.63	22.90	20.21

The increases and decreases in the above periods relate primarily to fluctuations in commodity prices, changes to operating netbacks as a result of operating cost efficiencies, the disposition of high operating cost properties, lower interest and financing charges and the realized hedging gains or losses from commodity contracts. In addition, production from new high rate, high decline North Dakota Bakken production impacts production and therefore funds from operations before commodity contracts.

In the past few quarters, an improvement in commodity prices and differentials and a lower Canadian dollar have combined to increase Arsenal's funds from operations. The Company experienced high differentials throughout most of 2013, especially in Canada.

OUTLOOK AND 2014 GUIDANCE

In Canada, Arsenal plans to expand its very successful oil exploration and development drilling at Princess, Alberta and in the US, the Company will complete its two high working interest operated Bakken wells at Stanley. Production from these projects should come on-stream late in Q2 2014 or in early Q3 2014.

Both oil and natural gas prices have increased significantly over the past few months. In addition, differentials in both Canada and in North Dakota have narrowed and the Canadian dollar has weakened thereby accentuating prices and therefore returns for producers. In Canada, production has remained relatively flat as facilities are being evaluated and upgraded, as required, to accomodate current and an expected increase in production from the

Princess area following the upcoming drilling program. In addition, normal annual maintenance work is being undertaken at a number of wells and facilities and on pipelines thereby reducing or curtailing production. In the US, production has declined slightly as wells are shut in for offsetting well completions or for maintenance.

Guidance

Funds from operations of $11.1 million in Q1 2014 resulted from higher production and improved commodity prices, lower differentials and a weaker Canadian dollar. With additional drilling planned at Princess and expected in North Dakota and with the completion of the Company's high working interest operated Bakken wells at Stanley, the expectation is that if prices remain at the current levels, both production and cash from operations will increase substantially in 2014.

Arsenal however will be proceeding prudently and cautiously with its 2014 capital program and provides the following 2014 guidance. Based on future strip pricing and the current scheduled timing of drilling and completions of wells in the US and in Canada, Arsenal expects an increase in 2014 funds from operations to approximately $50.0 million based on average 2014 production of approximately 4,400 Boe per day, exiting 2014 at approximately 4,750 Boe per day. Year end debt is estimated at approximately $71.0 million based on capital expenditures of approximately $44.0 million. Debt to cash flow at year end is estimated at approximately 1.4 : 1.

PRODUCTION AND REVENUE

Average Daily Production

Production for Q1 2014 averaged 4,108 Boe per day, a 1% increase from 4,048 Boe per day in Q4 2013 and an 8% increase from 3,806 Boe per day in Q1 2013. The increase from Q1 2013 is due to successful drilling and added production primarily at Princess, Alberta.

Average Daily Production	Three Months Ended March 31		
	2014	2013	% Change
Canada			
Heavy oil (bbls)	**46**	63	(26)
Medium oil and NGL's (bbls)	**1,635**	1,425	15
Natural gas (mcf)	**6,361**	5,730	11
Total Boe	**2,741**	2,443	12
US			
Light oil and NGL's (bbls)	**1,298**	1,292	-
Natural gas (mcf)	**415**	423	(2)
Total Boe	**1,367**	1,363	-
Corporate			
Heavy oil (bbls)	**46**	63	(26)
Oil and NGL's (bbls)	**2,933**	2,718	8
Natural gas (mcf)	**6,776**	6,153	10
Total Boe	**4,108**	**3,806**	8

By Commodity	Three Months Ended March 31		
	2014	2013	% Change
Heavy oil	**1%**	2%	-
Medium oil and NGL's	**40%**	37%	6
Light oil and NGLs	**32%**	34%	(7)
Natural gas	**27%**	27%	2

Production of heavy oil declined 26% during the current quarter from Q1 2013 due to natural production declines.

Production of medium oil in Canada increased 15% in the current quarter from Q1 2013 due to additional production from successful drilling at Princess in Alberta.

Production of light oil in North Dakota remained constant in spite of new Bakken wells drilled in the previous 12 month period. Production increased from these wells, but was offset in the current quarter by various wells shut-in due to inclement weather, minor operational issues, facility expansion or to complete offsetting wells and by expected natural decline rates. Production should increase as these operational issues are resolved and as new North Dakota wells drilled in Q1 2014 come on production.

Production of natural gas increased 10% in the current quarter from Q1 2013 as production declines were offset by gas production from new oil wells at Princess and at Stanley.

Production Profile

By Country	Three Months Ended March 31		
	2014	2013	% Change
Canada	**67%**	64%	4
US	**33%**	36%	(7)

The Company produces primarily in the provinces of British Columbia and Alberta in Canada accounting for 67% of total Q1 2014 production and in the state of North Dakota in the US that accounts for 33% of total Q1 2014 production. For Q1 2013, 64% of production originated in Canada and 36% from the US. Production in the US has increased over time with the drilling of high working interest, high initial production Bakken and Three Forks wells in North Dakota. Nine gross wells (2.61 net wells) were spud in North Dakota in the first quarter of 2014. These wells should be completed and on stream in mid to late Q2 2014 or early Q3 2014.

Production by Area

	Three Months Ended March 31				
	2014		2013		
AREA	**Boe/d**	**% of Total**	Boe/d	% of Total	**Change**
Canada					
Galahad (light oil)	**96**	**2**	115	3	**(17)**
Princess (medium oil and gas)	**1,052**	**26**	525	14	**100**
Chauvin (medium oil and gas)	**261**	**6**	309	8	**(16)**
Provost (medium oil and gas)	**424**	**10**	459	12	**(8)**
Consort (medium oil and gas)	**69**	**2**	73	2	**(5)**
Evi (light oil)	**138**	**4**	170	4	**(19)**
Desan (gas)	**567**	**14**	618	16	**(8)**
Others	**134**	**3**	174	5	**(23)**
Total Canada	**2,741**	**67**	2,443	64	**12**
US					
Stanley (light oil)	**1,097**	**27**	1,132	30	**(3)**
Lindahl (light oil)	**203**	**5**	163	4	**25**
Rennie Lake/Black Slough (light oil)	**47**	**1**	47	1	**-**
Lake Darling (light oil)	**20**	**-**	22	1	**(9)**
Total US	**1,367**	**33**	1,363	36	**-**
Total	**4,108**	**100**	3,806	100	**8**

Canadian Property Production

In Canada, the decrease in Galahad production in Q1 2014 from Q1 2013 relates to decline and depletion of a solution gas cap.

The doubling of production in Princess relates to successful new drilling activities.

Arsenal's other properties in Canada decreased due to no activity being undertaken and normal declines in production.

US Property Production

In the US, production over the past 12 months has been added from drilling of Bakken wells at Stanley and from Bakken and Three Forks wells at Lindahl. These wells exhibit high initial rate production with steep declines during the first couple of years. It is expected that production in these areas will increase over time with the drilling of additional Bakken and Three Forks wells.

Arsenal's other properties in the US experienced normal production declines.

Oil and Gas Revenue

	Three Months Ended March 31		
(000's Cdn. $)	**2014**	2013	% Change
Canada			
Heavy oil	**299**	328	(9)
Medium oil and NGL's	**12,667**	8,932	42
Natural gas	**3,065**	1,443	112
Total	**16,031**	10,704	50
US			
Light oil and NGL's	**11,283**	10,273	10
Natural gas	**293**	141	108
Total	**11,576**	10,414	11
Total			
Heavy oil	**299**	328	(9)
Oil and NGL's	**23,950**	19,205	25
Natural gas	**3,357**	1,584	112
Oil and natural gas revenues	**27,606**	21,117	31
Gain (loss) on realized commodity contracts	**(1,544)**	(22)	6,836
Oil and gas revenue after realized commodity contracts	**26,062**	21,095	24
Per boe before realized commodity contracts	**74.66**	61.65	21
Per boe after realized commodity contracts	**70.49**	61.58	14

In Canada, oil and natural gas revenues in Q1 2014 increased to $16.0 million up 50% from $10.7 million generated in Q1 2013. A 33% higher average price received per Boe combined with a 12% increase in daily average production, primarily related to Princess, accounted for this increase.

In the US, oil and natural gas revenues in Q1 2014 increased to $11.6 million up 11% from $10.4 million generated in Q1 2013. A 9% higher average crude price combined with higher natural gas prices accounted for this increase as production was comparable during the respective quarters.

Total oil and natural gas revenues of $27.6 million for Q1 2014 represented an increase of 31% over Q1 2013 due to a 21% increase in the average Boe price received and an 8% increase in production.

Commodity Price Risk Management

Financial instrument contracts are recorded in the consolidated financial statements at fair value at each reporting period with the change in fair value being recognized as an unrealized gain or loss.

The Company has a policy of entering into financial instrument contracts (commodity, interest rate and foreign exchange contracts) to stabilize funds from operations against volatile commodity prices in order to ensure a certain level of capital reinvestment, to protect the metrics of significant acquisitions and to protect against fluctuations in and exposure to interest and foreign exchange rates.

In Q1 2014, the Company recorded a loss of $3.0 million (loss of $2.8 million in Q1 - 2013) on its financial instrument (commodity price and interest rate) contracts, of which $1.5 million (Q1 2013 - $22,259) was realized.

As at March 31, 2014, the Company has a commodity risk management current liability recorded totaling $5.3 million. The liability has been calculated based on a March 31, 2014 WTI Canadian dollar strip price for the remainder of 2014 of approximately $109.20 Canadian ($98.50 US) per barrel and for Q1 of 2015 of approximately $104.18 Canadian ($93.60 US) per barrel.

The future liability will change with changes to the WTI forward strip prices and to the Canadian/US exchange rate.

As of May 5, 2014, the Company has the following commodity contracts in place with terms as follows.

($Cdn. unless otherwise noted)			
Commodity Sold	Volume Sold	Remaining Term	Pricing
Oil	300 bbl per day	April 1, 2014 - December 31, 2014	$92.75 per bbl
Oil	200 bbl per day	April 1, 2014 - December 31, 2014	$93.80 per bbl
Oil	200 bbl per day	April 1, 2014 - December 31, 2014	$89.80 USD per bbl
Oil	300 bbl per day	April 1, 2014 - December 31, 2014	$90.00 USD per bbl
Oil	300 bbl per day	April 1, 2014 - December 31, 2014	$90.00 USD per bbl
Oil	200 bbl per day	April 1, 2014 - December 31, 2014	$92.00 USD per bbl
Oil	500 bbl per day	June 1, 2014 - December 31, 2014	$104.61 per bbl
Oil	600 bbl per day	January 1, 2015 - March 31, 2015	$93.40 per bbl

In 2012, in order to mitigate the impact of future fluctuations in interest rates on its outstanding debt, the Company entered into a swap contract fixing the base interest rate on $20 million of banker's acceptance borrowings as outlined below. These rates are, under the Company's credit facility, subject to additional stamping fees from 2.00% to 3.50% depending on the debt to cash flow ratio, as defined, and as calculated at the Company's most recent quarter end.

Terms of the Company's interest rate swap are as follows:

Subject of Contract	Remaining Term	Notional Quantity	Reference	Strike Price
30 day BA rate	April 1, 2014 - February 13, 2015	$ 20,000,000	CAD - BA - CDOR	1.50%

As at March 31, 2014, the Company has a interest rate risk management current liability recorded totaling $43,890.

Royalties

	Three Months Ended March 31		
(000's Cdn. $)	**2014**	2013	% Change
Canada			
Heavy oil	**23**	13	78
Medium oil and NGL's	**1,867**	1,498	25
Natural gas	**322**	188	71
Total	**2,213**	1,700	30
US			
Light oil and NGL's	**3,147**	2,845	11
Natural gas	**62**	27	130
Total	**3,209**	2,872	12
Total			
Heavy oil	**23**	13	78
Oil and NGL's	**5,014**	4,344	15
Natural gas	**383**	215	79
Royalties	**5,421**	4,572	19

Percentage By Product	**Three Months Ended March 31**		
	2014	2013	% Change
Heavy oil	**8**	4	95
Oil and NGL's	**21**	23	(7)
Natural gas	**11**	14	(16)
Total	**20**	22	(9)

Percentage By Country	**Three Months Ended March 31**		
	2014	2013	% Change
Canada	**14**	16	(13)
US	**28**	28	1
Total	**20**	22	(9)

The Company's overall royalty rate for Q1 2014 averaged 20%, 14% in Canada and 28% in the US, down slightly from 22%, 16% in Canada and 28% in the US, in Q1 2013.

Going forward, the corporate royalty rate is expected to average in the 22% - 23% range. The rate fluctuates due to the timing of drilling low royalty rate wells in Canada, production increases from higher royalty rate, high decline US Bakken and Three Forks wells and to a lesser extent, commodity prices and production rates. Increases or decreases in the dollar value of royalties are commodity price related with higher commodity prices resulting in a higher royalty payable and lower commodity prices resulting in a lower royalty payable.

Operating Expenses

Operating costs include direct field costs such as contract operating fees and Company labor and benefits, electricity, fuel, property taxes, routine workovers and maintenance, processing and water disposal charges and transportation costs. Transportation costs reflect the cost of delivering production to the custody transfer point of the purchaser and are incurred primarily in British Columbia and Alberta.

On an absolute dollar basis, operating costs increased 4% or $304,218 due to generally higher field costs. On a Boe basis, operating costs decreased 4% or $21.29 per Boe due to an 8% increase in production.

Operating and Transportation	**Three Months Ended March 31**		
(000's Cdn. $)	**2014**	2013	**% Change**
Canada			
Heavy oil	**190**	174	9
Medium oil and NGL's	**5,450**	5,137	6
Natural gas	**1,210**	1,143	6
Total	**6,850**	6,454	6
US			
Light oil and NGL's	**1,004**	1,104	(9)
Natural gas	**20**	11	85
Total	**1,024**	1,115	(8)
Total			
Heavy oil	**190**	174	9
Oil and NGL's	**6,454**	6,242	3
Natural gas	**1,229**	1,153	7
Operating and transportation	**7,874**	7,569	4

Prices

Reference Prices	**Three Months Ended March 31**		
	2014	2013	% Change
WTI Cushing, Oklahoma ($U.S./bbl)	**98.68**	94.35	5
Light Oil Edmonton Par 40 API ($Cdn./bbl)	**100.18**	88.60	13
Hardisty Heavy 12 API ($Cdn./bbl)	**76.58**	50.18	53
Hardisty Bow River 24.9 API ($Cdn./bbl)	**83.87**	64.27	30
AECO (30 day spot) ($Cdn./MMBtu)	**5.63**	3.08	83
Henry Hub NYMEX Close ($U.S./MMBtu)	**4.73**	3.34	42
Foreign exchange ($Cdn./$U.S.)	**1.10**	1.01	9

The Company sells crude oil under 30-day evergreen contracts. Natural gas production is sold in the spot market. The commodity prices received by the Company are reflective of the movement in commodity prices over the comparative periods.

In Canada, the price the Company received for its heavy and medium oil and NGL's increased 23% and 24% respectively in Q1 2014 versus Q1 2013. These increases were in line with the Company's crude quality given a 53% increase in the average price for Hardisty Heavy and a 30% increase in Hardisty Bow River stream (24.9 API) in Q1 2014. The price received for natural gas increased 91% quarter over comparative quarter. The price received for natural gas generally tracks changes to the AECO price which was up 83% from Q1 2013.

In the US, the price received for light oil in Q1 2014 increased 9% over Q1 2013. The price of WTI quarter over comparative quarter increased 5%. This results from fluctuations in the North Dakota differentials and an ever increasing higher grade mix of oil (a higher component of sweet versus sour) as the percentage of Bakken light oil increases due to drilling. In addition, some of the increase is the result of the Company's tying in of its operated production that then is subject to a slightly lower differential. The price received for natural gas in the US increased 112% in Q1 2014 when measured against the 2013 comparative quarter. The increase, greater than the 42% increase in Henry Hub over the comparative quarter, relates to the strengthening of the US dollar and production of natural gas with a higher heat content thereby commanding a higher price.

Operating Netback

	Three Months Ended March 31			Three Months Ended March 31			
		2014			2013		**Corporate**
($Cdn.)	**Canada**	**US**	**Corporate**	Canada	US	Corporate	**% Change**
Heavy oil							
Revenue	**71.70**	**-**	**71.70**	58.07	-	58.07	**23**
Royalty	**(5.63)**	**-**	**(5.63)**	(2.34)	-	(2.34)	**141**
Operating and transportation	**(45.54)**	**-**	**(45.54)**	(30.85)	-	(30.85)	**48**
Operating netback per barrel	**20.53**	**-**	**20.53**	24.88	-	24.88	**(18)**
Medium and light oil and NGL's							
Revenue	**86.09**	**96.60**	**90.74**	69.63	88.31	78.51	**16**
Royalty	**(12.69)**	**(26.94)**	**(19.00)**	(11.68)	(24.46)	(17.76)	**7**
Operating and transportation	**(37.04)**	**(8.60)**	**(24.45)**	(40.04)	(9.49)	(25.52)	**(4)**
Operating netback per barrel	**36.36**	**61.06**	**47.29**	17.90	54.36	35.24	**34**
Natural gas							
Revenue	**5.35**	**7.84**	**5.51**	2.80	3.69	2.86	**92**
Royalty	**(0.56)**	**(1.65)**	**(0.63)**	(0.36)	(0.70)	(0.39)	**62**
Operating and transportation	**(2.11)**	**(0.53)**	**(2.02)**	(2.22)	(0.28)	(2.08)	**(3)**
Operating netback per mcf	**2.68**	**5.66**	**2.86**	0.22	2.71	0.39	**634**
Boe							
Revenue	**64.97**	**94.09**	**74.66**	48.68	84.89	61.65	**21**
Royalty	**(8.97)**	**(26.08)**	**(14.66)**	(7.73)	(23.41)	(13.35)	**10**
Operating and transportation	**(27.76)**	**(8.32)**	**(21.29)**	(29.35)	(9.09)	(22.10)	**(4)**
Operating netback per Boe	**28.24**	**59.69**	**38.71**	11.60	52.38	26.20	**48**

Canadian Netback

The Q1 2014 netback from Canadian heavy oil production decreased $4.35 per barrel or 18% from Q1 2013. Increased prices were offset by higher royalty and operating expenses. Royalties increased due to higher prices and minor adjustments and operating expenses increased as a result of workovers and maintenance work completed in the quarter.

The Q1 2014 netback from Canadian medium oil and NGL's increased $18.46 per barrel or 103% from Q1 2013 due to higher prices and lower Q1 2014 differentials.

The Q1 2014 netback from Canadian natural gas increased $2.46 per barrel from Q1 2013 due to improved gas prices.

US Netback

The Q1 2014 netback from the US light oil and NGL's increased $6.70 per barrel or 12% from Q1 2013 due to higher crude pricing in North Dakota.

The Q1 2014 netback from the US natural gas netback increased $2.95 per mcf or 109% from Q1 2013 due to higher prices.

Corporate Netback

Arsenal's Q1 2014 average price increased $13.01 per Boe or 21% to $74.66 per Boe from $61.65 per Boe received in Q1 2013. This increase is primarily attributed to higher crude and natural gas prices

Royalties in Q1 2014 averaged $14.66 per Boe versus $13.35 per Boe in Q1 2013. The 10% increase in Q1 2014 from Q1 2013 is due to higher prices and higher production.

Operating costs in Q1 2014 averaged $21.29 per Boe versus $22.10 per Boe in Q1 2013. The 4% decrease in Q1 2014 from Q1 2013 is due to additional volumes brought on at lower cost areas such as Princess, Alberta and North Dakota. Operating costs are expected to decline to the range of $19.00 to $21.00 per barrel.

Arsenal's Q1 2014 corporate operating netback increased $12.51 per Boe or 48% to $38.71 per Boe from $26.20 per Boe in Q1 2013 due to higher prices and higher production.

General and Administrative Expenses

	Three Months Ended March 31		
(000's Cdn. $)	**2014**	2013	% Change
Gross expenditures	**1,648**	1,777	(7)
Overhead recovery	**(499)**	(561)	(11)
Capitalized overhead	**(162)**	(123)	32
Net general and administrative expense	**987**	1,093	(10)
Net general and administrative per boe	**2.67**	3.19	(16)

For Q1 2014, gross general and administrative expenditures were slightly lower than in Q1 2013 by $129,071. On a net basis, the general and administrative expenditures decreased by $106,604. While compensation costs and consulting fees increased slightly, lower office operation, legal fees and corporate expenses resulted in the overall decrease in general and administrative expenditures.

Overhead recovery decreased due to the decrease in the dollar value of operated capital projects incurred in the current quarter versus the previous comparative quarter. The number of operated producing wells increased slightly over the prior comparative quarter.

The Company capitalizes salary, benefits and bonus overhead directly related to exploration and development activities. For Q1 2014, the Company's capitalized overhead, excluding share based compensation, totalled $162,500 (Q1 2013 - $122,500) up due to one additional geological employee capitalized in the current period versus the prior period and due to slightly increased compensation costs.

On a Boe basis, general and administrative costs for the current quarter decreased to $2.67 per Boe from $3.19 per Boe in Q1 2013, the result of a 10% decrease in net expenditures and an 8% increase in production .

General and administrative expenses should decrease on a Boe basis in 2014 as average production increases during 2014 from drilling at Princess, Alberta and in North Dakota.

Exploration and Evaluation Expenses

	Three Months Ended March 31		
(000's Cdn. $)	**2014**	2013	% Change
Exploration and evaluation expenses	**644**	55	1,067
Per Boe	**0.17**	0.02	981

Arsenal expenses all pre-license costs, all seismic expenditures and all dry hole costs. Recoveries of these expenses are credited to exploration and evaluation expenses. In Q1 2013, the Company incurred certain expenses related to its seismic expenditure program.

During Q1 2014, the Company shot 3D seismic at Princess, Alberta.

Exploration and Evaluation Impairment

Exploration and evaluation costs are capitalized as exploration and evaluation assets according to the expenditure.

Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are allocated to cash-generating units.
On March 31, 2014 and on March 31, 2013, no indicators of impairment existed.

Property, Plant and Equipment Impairment

The carrying amounts of the Company's property, plant and equipment are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the assets' fair value is estimated based on certain industry value metrics. For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or "CGU"). The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its fair value. Impairment losses are recognized in profit or loss. Impairment losses recognized in respect of CGU's reduce the carrying amounts of the other assets in the unit (group of units) on a pro rata basis.

On March 31, 2014 and on March 31, 2013, no indicators of impairment existed.

The fair value amount of the Company's CGU's are sensitive to decline changes in commodity prices. Impairment charges could be recorded in future periods should commodity prices decline. Alternatively, an improvement of commodity prices could reverse impairment charges recorded to date, less applicable depletion and depreciation charges.

Interest and Other Financing Expenses

	Three Months Ended March 31		
(000's Cdn. $)	**2014**	2013	% Change
Interest and other financing charges	**663**	714	(7)
Per Boe	**1.79**	2.08	(14)

Interest and other financing expenses include interest, bank charges and fees and other charges paid on the Company's credit facility, interest paid on the Company's unspent flow-through share obligation and other government and vendor charges.

Interest and other financing fees decreased 7% in the Q1 2014 due to lower fees and lower borrowing rates in Q1 2014 versus Q1 2013. The average borrowing balance for Q1 2014 was $71.2 million versus $66.2 million for Q1 2013.

The Company's banking syndicate is currently reviewing the Company's credit facility of $90.0 million. The review incorporates the year-end independent engineering report as well as Q1 2014 activity. It is expected that the facility availability will remain substantially unchanged. The review must be completed by May 31, 2014.

Rates under the current facility range from Canadian or US prime plus 1.00% to 2.50% on prime based loans and from the base rate plus 2.00% to 3.50% on bankers' acceptances and on Libor based loans.

Transaction Costs

	Three Months Ended March 31		
($Cdn.)	**2014**	**2013**	**% Change**
Transaction costs	-	201	(100)
Per Boe	-	0.59	(100)

In Q4 2012, the Company undertook an exercise to analyze efficient alternatives by which excess cash flow from the Company's North Dakota properties could be returned to shareholders. Costs related to this exercise for legal, accounting and financial advice totaled approximately $1.6 million of which $1.4 million was recorded in 2012 and $201,434 was recorded in Q1 2013.

Depletion and Depreciation Expense

	Three Months Ended March 31		
(000's Cdn. $)	**2014**	2013	% Change
Depletion and depreciation	**6,762**	6,145	10
Per boe	**18.29**	17.94	2

On an absolute dollar basis, an 8% increase in production resulted in an increase of 10% in depletion and depreciation to $6.8 million. On a Boe basis, depletion and depreciation increased 2% to $18.29 per Boe in Q1 2014 versus $17.94 per Boe in Q1 2013 due primarily to a year end reduction in US reserves.

In Canada, the depletion and depreciation rate per Boe in Q1 2013 increased from $16.93 per Boe in Q1 2013 to $17.23 per Boe in Q1 2014.

In the US, a negative year end reserve adjustment increased the depreciation and depletion rate from $19.74 per Boe in Q1 2013 to $20.40 per Boe in Q1 2014.

Overall, the Company's depreciation and depletion rate increased slightly by 2% to $18.29 per Boe due primarily to US reserve decreases.

Share-based Compensation

	Three Months Ended March 31		
(000's Cdn. $)	**2014**	2013	% Change
Share-based compensation expense	**920**	205	349
Per boe	**2.49**	**0.60**	316

At December 31, 2013 the Company determined that, in certain circumstances, it would cash settle certain stock options outstanding. The Company recorded an incentive (share-based) compensation liability of $809,216 with a corresponding charge to equity. As a result of the increase in the Company's share price during Q1 2014, the fair value of the Company's incentive compensation liability was remeasured at March 31, 2014 resulting in an increase in the liability to $1.7 million. The change in fair value resulted in a charge to earnings of $920,310.

During the three month period ended March 31, 2014, no additional options were granted (March 31, 2013 – nil). During the three months ended March 31, 2014, 10,000 options (March 31, 2013 - 58,000) were exercised at a weighted average price of $2.05 (March 31, 2013 $5.40) per share. No options were forfeited or expired unexercised during the three months ended March 31, 2014 (March 31, 2013 – nil).

Increases or decreases in share-based compensation in the various reporting periods will result from changes in the fair market value of the Company's liability to cash settle stock options. This change is based on increases or decreases in the Company's share price during the period.

No share-based compensation was capitalized during Q1 2014 (March 31, 2013 - $55,065).

Gain on Sale of Property

	Three Months Ended March 31		
(000's Cdn. $)	**2014**	2013	% Change
(Gain) loss on sale of property	**-**	8	-
Per boe	**-**	**0.02**	-

During Q1 2013, the Company disposed of certain non-core properties for cash and/or the assumption of decommissioning liabilities. These sales resulted in a gain of $7,609 in Q1 2013.

The Company is continuing to evaluate its portfolio of properties and based on this ongoing evaluation and assessment, additional property dispositions on non-core properties is possible.

Accretion

	Three Months Ended March 31		
(000's Cdn. $)	**2014**	**2013**	% Change
Accretion	**306**	226	35
Per boe	**0.83**	**0.66**	25

Accretion is the increase or decrease, in the reporting period, in the present value of the Company's decommissioning liabilities that are estimated based on current costs, inflated at a rate of 1.5% and discounted using a risk free interest factor of 3.0% in Canada and 3.5% in the US. Accretion also includes additional expenditures incurred to decommission well sites and facilities over and above the estimate contained in the decommissioning liability account.

Accretion increased in Q1 2014 by 35% from Q1 2013 due to an increase in the discount rates in both Canada and the US.

Income Tax Expense

(000's Cdn. $)	**2014**	**2013**	% Change
Current tax expense	**171**	**-**	-
Deferred tax expense	**987**	2,577	(62)
Total	**1,158**	**2,577**	(55)
Per boe	**3.13**	**7.52**	(58)

For the three months ended March 31, 2014, the Company has recorded income tax expense of $1.2 million (March 31, 2013 – $2.6 million). In the US, the Company has recorded an income tax provision of $1.2 million of which $170,623 represents current tax relating to Alternate Minimum Tax ("AMT" see below). In Canada, the Company has not recorded an income tax provision as the Company has losses from operations and Canadian tax pools in excess of $110 million. As such, the Company determined that it was no longer probable that the Canadian entity will have sufficient profits to offset losses and tax pools and therefore has not recorded a provision nor has recognized a deferred tax asset.

During Q1 2014, the Company recorded a reduction of $38,200 relating to tax credits recognized on expenditures incurred under the issuance of flow-through shares in 2013.

In the US, the Company was taxable under the provisions of the AMT in 2013 and may, depending on income and capital expenditures, be subject to AMT in 2014 and onwards. The AMT attempts to ensure that corporations that benefit from certain deductions (such as intangible drilling costs, accelerated depreciation and non-capital losses) pay at least a minimum tax. In calculating the AMT, these deductions are reduced from the amounts allowed under the calculation of income tax. The tax credit for AMT payments can be used to offset future regular income taxes payable.

For the three months ended March 31, 2013, the Company recorded an income tax expense of $2.6 million. Of this provision, $1.8 million related to the reversal of a deferred tax asset in Canada as the Company determined that it was no longer probable that the Canadian entity will have sufficient profits to offset the deferred tax asset.

At March 31, 2014, the deferred tax liability recorded in the Company's Statement of Financial Position of $16.2 million relates entirely to the US operations.

Funds Provided By Operating Activities, Funds From Operations and Net Loss Per Share

	Three Months Ended March 31		
(000's Cdn. $ except per share amounts)	**2014**	2013	Change
Net cash from operating activities	**7,629**	8,651	(12)
Funds from operations	**11,053**	7,139	55
Per share			
Basic	**0.69**	0.46	50
Diluted	**0.69**	0.45	52
Net income (loss)	**1,028**	(4,648)	(122)
Per share			
Basic	**0.06**	(0.30)	(121)
Diluted	**0.06**	(0.30)	(121)

Funds from operations for Q1 2014 totaled $11.1 million ($0.69 per share basic and diluted) or $29.89 per Boe versus $7.1 million ($0.46 per share basic and $0.45 per share diluted) or $20.84 per Boe for Q1 2013. In Q1 2014, production increased 8% while the average crude price received increased 21% increasing operating margins by $12.51 per Boe to $38.71 per Boe. The realized hedging loss in Q1 2014 totaled $1.5 million ($4.18 per Boe) versus a loss of $22,259 ($0.06 per Boe) in Q1 2013. Due to increased production, other cash expenses decreased by $0.66 per Boe. General and administrative expenses decreased by $0.52 per Boe and interest and other financing costs decreased by $0.30 per Boe. A foreign exchange realized gain of $0.29 offset AMT reducing the cash netback by $0.17 in Q1 2014 versus a loss on realized foreign exchange of $0.02 per Boe in Q1 2013.

The Company's net income for Q1 2014 of $1.0 million ($0.06 per share basic and diluted) improved significantly from the net loss of $4.6 million ($0.30 per share basic and diluted) in Q1 2013. In Q1 2014, the Company's operating margin improved by $5.3 million over Q1 2013 due to a 21% increase in the average price received per Boe. The Company's realized and unrealized risk management loss increased slightly ($220,773) in Q1 2014 over Q1 2013 while other expenses increased $858,383 in Q1 2014 versus Q1 2013 resulting in before tax income of $2.2 million in Q1 2014 versus a loss of $2.1 million in Q1 2013. The Q1 2014 tax provision, all related to US operations was $1.2 million versus a tax provision in Q1 2013 of $2.6 million. The Q1 2013 tax provision comprises a reversal of the deferred tax asset related to the Canadian company of $1.8 million as the probability test to recognize the deferred tax asset was less than certain. In addition, the Company recorded a deferred tax provision related to US operations of $801,868.

Comprehensive Income (Loss)

The Company's comprehensive income or loss includes unrealized foreign exchange gains and losses resulting from the translation into Canadian dollars of the Company's US subsidiary. Net income was increased for a translation gain on foreign operations by $948,262 for Q1 2014 (gain of $288,255 for Q1 2013). Comprehensive income therefore for Q1 2014 totaled $2.0 million versus a comprehensive loss of $4.4 million for Q1 2013.

Net Income (Loss) Per Boe

	Three Months Ended March 31	
($Cdn.)	**2014**	2013
Oil and gas revenue	74.66	61.65
Royalties	(14.66)	(13.35)
Operating and transportation	(21.29)	(22.10)
Operating netback per Boe	**38.71**	26.20
Realized gain (loss) on risk management contracts	(4.18)	(0.06)
Realized gain (loss) on foreign exchange	0.29	(0.02)
General and administrative	(2.67)	(3.19)
Interest and other financing charges	(1.79)	(2.08)
Current tax expense	(0.46)	-
Funds from operations netback per Boe	**29.89**	20.84
Unrealized gain (loss) on risk management contracts	(3.90)	(8.00)
Unrealized gain (loss) on foreign exchange	2.80	1.04
Depletion and depreciation	(18.29)	(17.94)
Accretion	(0.83)	(0.66)
Exploration and evaluation impairment	0.00	-
Property, plant and equipment impairment	0.00	-
Exploration and evaluation - directly expensed	(1.74)	(0.16)
Gain (loss) on sale of property and equipment	-	0.02
Share-based compensation	(2.49)	(0.60)
Transaction costs	-	(0.59)
Deferred tax expense	(2.67)	(7.52)
Net income (loss) per Boe	**2.78**	(13.57)

Summary of Quarterly Results

	2014	2013				**2012**		
(000's Cdn. $)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Production (Boe)								
Total	**369,746**	372,410	397,702	337,311	342,561	361,886	339,815	323,485
Per day	**4,108**	4,048	4,323	3,707	3,806	3,934	3,694	3,555
Oil and gas revenue	**27,606**	24,112	30,177	22,405	21,117	22,351	20,175	18,444
Funds from operations	**11,053**	9,013	11,695	10,011	7,139	10,000	7,782	6,538
Per share - basic and diluted ($)	**0.69**	0.56	0.73	0.63	0.46	0.64	0.50	0.41
- diluted ($)	**0.69**	0.56	0.72	0.63	0.45	0.63	0.49	0.41
Net income (loss)	**1,028**	(396)	(627)	2,957	(4,648)	(896)	(1,474)	7,030
Per share - basic and diluted ($)	**0.06**	(0.02)	(0.04)	0.19	(0.30)	(0.06)	(0.09)	0.44
- diluted ($)	**0.06**	(0.02)	(0.04)	0.19	(0.30)	(0.06)	(0.09)	0.44
Total assets	**202,146**	191,922	191,000	189,690	188,761	182,457	179,402	174,726
Total debt (1)	**74,294**	70,422	69,147	67,078	70,641	68,492	64,386	60,054
Shares outstanding	**16,090**	16,080	16,070	16,070	15,694	15,595	15,641	15,619

(1) Includes bank debt and working capital but excludes risk management contracts whether current or long term assets or liabilities.

Arsenal's quarterly results have fluctuated significantly in the past eight quarters due to a variety of factors that include, the Company's risk management contratcs, the awarding and recording of stock options, commodity price and production swings, the widening differentials, the timing of drilling and completions particularly in the US and in Alberta at Evi and Princess, the rationalization of properties and operating costs and in the some quarters, the shutting in of some natural gas production due to low prices. Arsenal has been and expects to continue to rationalize its asset base focusing on properties with a long reserve life and high netbacks where the Company has a strategic, technical or financial advantage. Quarterly results therefore will continue to fluctuate somewhat and will depend somewhat on property dispositions and property shut-ins, the movement in commodity prices particularly for oil, the differentials in medium, heavy oil and North Dakota oil and the timing of drilling programs in North Dakota and Canada. With the establishment and maintenance of a core low decline property base coupled with the continuing implementation of operational efficiencies, a more stable commodity market and continued drilling success in North Dakota, the Company expects its established production base to increase steadily which should lead to more comparative and stable results going forward.

Segmented Information

Three months Ended March 31, 2014 (000's Cdn. $)	Canada	U.S	Total
Production (Boe/d)	2,741	1,367	**4,108**
Oil and gas revenue	16,031	11,575	**27,606**
Operating income	6,968	7,343	**14,311**
Funds from operations	6,137	4,916	**11,053**
Income (loss) before income taxes	398	1,788	**2,186**
Income (loss) after income taxes	436	592	**1,028**
Exploration and evaluation assets (as at March 31, 2014)	9,919	-	**9,919**
Property, plant and equipment (as at March 31, 2014)	95,672	79,233	**174,905**
Property, plant and equipment expenditures	3,696	8,369	**12,065**
Exploration and evaluation expenditures	276		**276**
Exploration and evaluation expenses	644	-	**644**
Property dispositions	-	-	**-**
Property acquisitions	152		**152**

For Three Months Ended March 31, 2013 (000's Cdn. $)	Canada	U.S	Total
Production (Boe/d)	2,443	1,363	3,806
Oil and gas revenue	10,704	10,414	21,117
Operating income	2,550	6,426	8,976
Funds from operating activities	2,227	4,912	7,139
Income (loss) before income taxes	(4,244)	2,172	(2,071)
Income (loss) after income taxes	(6,018)	1,370	(4,648)
Exploration and evaluation assets (as at March 31, 2013)	9,013	**-**	9,013
Property, plant and equipment (as at March 31, 2013)	99,369	63,780	163,150
Capital expenditures	3,799	6,828	10,627
Exploration and evaluation expenditures	951	-	951
Exploration and evaluation expenses	55		55
Property dispositions	-	-	-
Property acquisitions	-	-	-

Bank Loan, Liquidity and Capital Resources

Capital Management

A strong capital base results in increased market confidence, an essential factor in maintaining existing shareholders and in attracting new investors. The Company is committed to establishing and maintaining a strong capital base to ensure the Company can maintain and possibly increase its dividend and has access to the equity and debt markets when deemed advisable. The Company continually monitors the risk reward profile of its exploration and development projects, its production profile and the economic indicators in the market including commodity prices, interest rates and foreign exchange rates. It then determines increases or decreases to its capital budget and what, if any, additional initiatives may need to be implemented.

The Company monitors its capital base based primarily on its debt to annualized funds flow ratio and its debt to equity ratio. Debt includes bank borrowings, plus or minus working capital and excludes long term decommissioning obligations and risk management contracts (whether an asset or an obligation). Annualized funds flow is calculated as cash flow from operations, before changes in non-cash working capital, seismic expenses, transaction costs and decommissioning obligations settled, from the Company's most recent quarter multiplied by four.

The Company's debt to cash flow ratio at March 31, 2014 is 1.68 : 1. The ratio can and will fluctuate based on the timing of capital expenditures, the timing of bringing successful wells on production and on commodity prices and expenses. The Company's debt to equity ratio is 1.38 : 1. Both of these ratios are within acceptable ranges of the Company's target ratios.

The Company expects to focus the greater part of its remaining 2014 expenditures on drilling wells in Alberta at Princess and Columbia and in the US at Lindahl and Stanley in North Dakota.

(000's Cdn. $)	March 31, 2014
Bank loan	70,997
Working capital deficiency (1)	3,297
Total debt	74,294
Annualized funds from operations	44,214
Net debt to annualized funds flow ratio	**1.68**
Shareholders' Equity	53,934
Debt to equity	**1.38**

(1) excludes current portion of risk management contracts

The Company's share capital is not subject to external restrictions.

There were no changes in the Company's approach to capital management during Q1 2014.

Credit Facility

The Company’s syndicated credit facility is $90.0 million and is subject to the syndicates’ semi-annual review by May 31, 2014. It is expected that the facility will be renewed at it’s current level with all terms and conditions substantially unchanged.

The credit facility is available in Canadian and/or US dollar prime loans or in Bankers Acceptances and/or Libor borrowings. Interest on the Company’s credit facility is at rates ranging from Canadian or US prime plus 1.00% to 2.50% on prime based loans and from the base rate plus 2.00% to 3.50% on Bankers Acceptances and on Libor based loans. The interest rate is set based on the Company’s debt, as calculated for this purpose to include bank loan plus working capital (excess or deficiency), outstanding letters of credit and other miscellaneous items, if any, but excludes decommissioning obligations and risk management contracts (whether an asset or an obligation) to trailing funds flow ratio (funds flow for the last two quarters annualized) adjusted for interest and other financing expenses, expensed seismic expenditures, transaction costs, realized hedging gains or losses and any unusual or non-recurring items.

The credit facility has a revolving period of 364 days plus one year and is extendible annually. If not extended, the credit facility will automatically convert to a one year non-revolving term loan and all obligations under the credit facility are to be repaid or paid at the end of the one year period.

The credit facility is secured by an unlimited liability guarantee to the lenders, an ISDA Master Agreement, a demand debenture in the amount of $300 million granting a first priority security interest over all present and after acquired personal property and a first floating charge over all present and after acquired petroleum and natural gas interests and mortgages creating specific fixed charges on some of the oil and gas properties of the Company in North Dakota.

The credit facility is subject to certain positive and negative covenants including a covenant not to dispose of assets or property having a fair aggregate value exceeding 5% of the borrowing base without an assessment of an adjustment to the borrowing base and the facility and to not make distributions (defined to include dividends and purchases under a NCIB) in excess of $5.0 million annually. In addition, the credit facility is subject to a semiannual borrowing base review based on internally generated engineering.

The Company’s credit facility has a financial covenant that, without the written consent of the lender, would result in a breach of the agreement. The Company cannot permit:

> The adjusted working capital ratio (as defined in the agreement to include the unutilized portion of the facility and to exclude the value of any risk management contracts) to fall to below 1 : 1.

At March 31, 2014, the Company was in compliance with this covenant.

At March 31, 2014, debt under the credit facility amounted to $71.0 million (December 31, 2013 - $69.1 million).

Total debt at March 31, 2014 was $74.3 million, up from $70.4 million at December 31, 2013 and from $70.6 million at March 31, 2013. Debt has increased from December 31, 2013 due to higher capital expenditures particularly in North Dakota and an increase in the liability related to the cash settlement of stock options and from March 31, 2013 due to the inclusion in current liabilities of $1.0 million of decommissioning liabilities and the recognition of a current liability relating to the cash settlement of stock options .

In Q2 2014, the Company expects to complete it’s two high working interest operated Bakken wells in North Dakota as well as commence it’s Princess, Alberta drilling program. Production from the North Dakota wells is expected to commence late in Q2 2014 or in early Q3 2014 while production from Princess drilling program should commence in Q3 2014.

The Company has attempted to mitigate the impact of future fluctuations in interest rates on its outstanding debt by entering into a swap contract fixing the base interest rate on $20 million of banker's acceptance borrowings as outlined below. These rates are, under the Company's credit facility, subject to additional stamping fees from 2.00% to 3.50% depending on the debt to cash flow ratio, as defined, and as calculated at the Company's most recent quarter end. At March 31, 2014, the Company recorded a liability of $43,890 under this contract.

Subject of Contract	Remaining Term	Notional Quantity	Reference	Strike Price
30 day BA rate	April 1, 2014 - February 13, 2015	$ 20,000,000	CAD - BA - CDOR	1.50%

Liquidity

Crude prices received by the Company in Q1 2014 increased due to higher prices, improved differentials and a lower Canadian dollar. Production in Q1 2014 averaged 4,108 Boe per day and is expected to increase during 2014. These factors combined, resulted in cash from operating activities of $11.1 million in Q1 2014. It is expected that prices, while they may decline somewhat, will remain in a very acceptable range and that over 2014, production will increase. With an acceptable pricing environment and increased production, it is expected that the Company will realize record cash flow for 2014. These funds combined with funds available under our current credit facility should be sufficient for the Company to undertake its capital expenditure program and dividend payments to shareholders.

Share Capital

On March 27, 2014, the Company announced its intention to make a normal course issuer bid ("NCIB") that commenced April 1, 2014 and ends March 31, 2015. A total of 804,506 common shares may be acquired under the bid representing 5% of the common shares outstanding as of March 26, 2014. To date, the Company has purchased common shares at an average price of $6.82 per share plus expenses.19,900

At March 31, 2014, the Company has 16,090,119 common shares and 1,257,600 options outstanding at a weighted average price of $6.44 per share.

Common Shares

	Period Ended		Year Ended	
	March 31, 2014		December 31, 2013	
(000's)	**Shares**	**$**	Shares	$
Balance - beginning of period	**16,080**	**137,705**	15,595	135,646
Issued under private placements	-	-	635	**3,050**
Share issue costs	-	-	-	**(325)**
Issued on exercise of options	**10**	**51**	75	**166**
Transferred from contributed surplus on exercise of options	-	-	-	**961**
Cancelled on expiration of amalgamation exchange provision	-	-	(18)	-
Purchases under normal course issuer bid	-	-	(207)	**(1,793)**
Balance - end of period	**16,090**	**137,756**	16,080	137,705

Options

	Period Ended	Year Ended
(000's)	**March 31, 2014**	December 31, 2013
Balance - beginning of period	**1,268**	1,529
Cancelled (forfeited or expired unexerecised)	-	(235)
Exercised	**(10)**	(75)
Option "puts" accepted by Company	-	(237)
Options issued	-	286
Balance - end of period	**1,258**	1,268

As of the date of this MD&A, the Company has 16,075,219 common shares and 1,228,667 share options outstanding.

Related Party Transactions

The Company had no related party transactions during the three months ended March 31, 2014 or March 31, 2013.

Capital Expenditures

2014 Drilling Statistics	**Q1**	
	Gross	Net
Operated	4.00	3.69
Non-operated	7.00	0.92
	11.00	4.61
Canada	2.00	2.00
US	9.00	2.61
	11.00	4.61
Light oil	11.00	4.61
Heavy oil	-	-
Natural gas	-	-
Dry and abandoned	-	-
	11.00	4.61
Exploration		
Development	11.00	4.61
	11.00	4.61

Capital expenditures for Q1 2014 to property, plant and equipment totaled $11.9 million up from $10.6 million in Q1 2013. Expenditures in Q1 2014 were incurred in Canada ($3.5 million) to drill wells at Princess, to equip wells and on facilities and pipelines and in the US ($8.4 million) to drill 2.61 net Bakken and Three Forks wells and on equipment and pipelines.

Expenditures on exploration and evaluation totaled $276,240 in Q1 2014 versus $951,073 in Q1 2013. These expenditures were incurred to purchase land in the Company's exploratory prospect areas of Columbia and Princess, both in Alberta.

The Company shot 3D seismic at Princess, Alberta incurring approximately $644,283 of exploration and evaluation expenses.

Total Company

Property, Plant and Equipment Expenditures

(000's Cdn. $)	Three Months Ended March 31, 2014	2013
Land	**245**	140
Drilling and completions	**9,765**	9,131
Capitalized general and administrative	**162**	174
Production equipment, facilities and tie-ins	**1,706**	1,234
Other	**(221)**	224
Total property plant and equipment additions	**11,657**	10,903
Non-cash additions	**256**	(276)
Total Property, Plant and Equipment Expenditures	**11,913**	10,627

Exploration and Evaluation Expenditures

(000's Cdn. $)	Three Months Ended March 31, 2014	2013
Land	**210**	951
Drilling and completions	**66**	-
Total Exploration and Evaluation Expenditures	**276**	951

Property Acquisitions

(000's Cdn. $)	Three Months Ended March 31, 2014	2013
Total Property Acquisitions	**152**	-

Exploration and Seismic Expenses

(000's Cdn. $)	Three Months Ended March 31, 2014	2013
Seismic expenditures	**644**	55
Proceeds on sale of seismic	**-**	-
Total Exploration and Seismic Expenses	**644**	55

Canada

Property, Plant and Equipment Expenditures

(000's Cdn. $)	Three Months Ended March 31, 2014	2013
Land	-	127
Drilling and completions	**1,754**	2,727
Capitalized general and administrative	**162**	174
Production equipment, facilities and tie-ins	**1,593**	823
Other	**(246)**	119
Total property plant and equipment additions	**3,263**	3,970
Non-cash additions	**281**	(171)
Total Property, Plant and Equipment Expenditures	**3,544**	3,799

Exploration and Evaluation Expenditures

(000's Cdn. $)	Three Months Ended March 31, 2014	2013
Land	**210**	951
Drilling and completions	**66**	-
Total Exploration and Evaluation Expenditures	**276**	951

Property Acquisitions

(000's Cdn. $)	Three Months Ended March 31, 2014	2013
Total Property Acquisitions	**152**	-

Exploration and Seismic Expenses

(000's Cdn. $)	Three Months Ended March 31, 2014	2013
Seismic expenditures	**644**	**55**
Proceeds on sale of seismic	**-**	**-**
Total Exploration and Seismic Expenses	**644**	55

United States

Property, Plant and Equipment Expenditures

(000's Cdn. $)	Three Months Ended March 31, 2014	2013
Land	**245**	13
Drilling and completions	**8,011**	6,404
Capitalized general and administrative	**-**	-
Production equipment, facilities and tie-ins	**113**	411
Other	**25**	105
Total property plant and equipment additions	**8,394**	6,933
Non-cash additions	**(25)**	(105)
Total Property, Plant and Equipment Expenditures	**8,369**	6,828

Decommissioning Obligations

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the decommissioning obligations associated with the Company's retirement of oil and gas properties:

(000's Cdn. $)	**Period Ended March 31, 2014**	Year Ended December 31, 2013
Total decommissioning obligations at beginning of year	**36,321**	37,373
Obligations settled	**(234)**	(1,039)
Obligations disposed of	**-**	(32)
Obligations incurred	**315**	602
Change in estimate	**(571)**	(2,503)
Foreign currency translation	**119**	215
Accretion expense	**306**	1,705
Total decommissioning obligations at end of period	**36,256**	36,321
Recorded as folows:		
Decommissioning obligations to be incurred within one year	**1,000**	1,000
Decommissioning obligations to be incurred beyond one year	**35,256**	35,321
Total decommissioning obligations at end of period	**36,256**	36,321

Disclosure Controls and Procedures

There were no changes to disclosure controls and procedures during the three months ended March 31, 2014.

Internal Controls Over Financial Reporting

There were no changes to internal controls over financial reporting during the three months ended March 31, 2014.