MANAGEMENT DISCUSSION AND ANALYSIS

SUMMARY OF FINANCIAL AND OPERATIONAL RESULTS		
	Three Months Ended March 31	
(000'S Cdn. $ except per share amounts)	**2016**	**2015**
FINANCIAL		
Oil and gas revenue	**7,570**	13,866
Cash (used in) provided by operating activities	**(227)**	17,109
Funds (used in) from operations	**(263)**	15,760
Per share - basic	**(0.01)**	0.88
Per share - diluted	**(0.01)**	0.87
Net loss	**(5,779)**	(466)
Per share - basic and diluted	**(0.30)**	(0.03)
Net debt	**53,169**	57,229
Capital expenditures	**896**	6,671
Property dispositions	**(1,060)**	-
Wells drilled - Oil	**-**	0.89
Common Share Trading Range		
High	**1.44**	6.84
Low	**0.87**	3.05
Close	**1.25**	3.30
Average daily volume	**17,402**	26,758
Shares outstanding - end of period	**19,423**	17,897
OPERATIONAL		
Daily production		
Heavy oil (bbl/d)	**4**	40
Medium oil and NGL's (bbl/d)	**1,495**	1,698
Light oil and NGLs (bbl/d)	**965**	1,392
Natural gas (mcf/d)	**3,559**	5,648
Oil equivalent (boe/d @ 6:1)	**3,058**	4,071
Realized commodity prices ($Cdn.)		
Heavy oil (bbl)	**40.10**	42.20
Medium oil and NGL's (bbl)	**29.46**	41.16
Light oil and NGLs (bbl)	**34.31**	49.31
Natural gas (mcf)	**1.65**	2.46
Oil equivalent (boe @ 6:1)	**27.21**	37.85
Netback ($ per boe)		
Revenue	**27.21**	37.85
Royalty	**(5.99)**	(9.74)
Operating and transportation	**(15.93)**	(16.37)
Operating netback per boe	**5.29**	11.74
General and administrative	**(4.27)**	(3.01)
Interest and other financing	**(2.20)**	(1.46)
Realized gain (loss) on risk management contracts	**(0.26)**	35.84
Other (FX and current tax)	**0.49**	(0.08)
Fund from (used by) operations per Boe	**(0.94)**	43.02

1 Funds from operations is not recognized by IFRS but it is used by the Company, investors, analysts, bankers and others to evaluate and compare oil and gas exploration, development and production entities. The Company determines funds from operations as net cash from operating activities before the net change in non-cash operating working capital, decommissioning obligations settled, exploration and evaluation expenses and transaction costs, if any. Funds from operations does not have a standardized measure prescribed by GAAP and therefore may not be comparable with the calculations of similar measures for other companies.

2 Funds from operations and net loss per share basic are calculated based on the weighted average number of common shares outstanding during the respective periods. Funds from operations and net loss per share diluted are calculated based on the weighted average number of common shares outstanding for the respective period adjusted for dilutive instruments (stock options and share awards).

3 Total debt includes bank borrowings, plus or minus working capital. Net debt excludes decommissioning obligations and risk management contracts (whether an asset or an obligation and whether classified as current or long term).

4 Funds from operations per Boe is funds from operations calculated on a Boe basis.

Q1 2016 Financial and Operating Highlights

In North Dakota, the operator of the Lindahl property commenced the drill-out of the six wells spud in Q1 2015. With the drill-out now completed on five of the six wells drilled, production from these wells should add approximately 225 Boe/d of primarily light oil to the Company's Q2 2016 production base.

The Company continues to proactively deal with low commodity prices by reducing ongoing expenditures and by attempting to sell properties in both Canada and the US.

In Q1 2016, the Company sold its natural gas property in British Columbia for net proceeds (subject to adjustment) of $1.1 million. While the property produced approximately 459 Boe/d in 2015, in the current low price natural gas price environment, the property had negative operating margins for the last few quarters and a poor cash flow outlook without a significant increase in natural gas prices. As part of the sale, the Company transferred approximately $2.9 million (balance sheet) of decommissioning liabilities related to the properties to the buyer.

In Q1 2016, the Company further reduced ongoing general and administrative costs by reducing work hours and salary for a number of employees, trimming the head office head count by two and further reducing employee benefits. These changes have resulted in slightly higher short term costs due to severance costs involved but will result in lower costs going forward. In response to low commodity prices, the Company continues to defer any further drilling and development until later in the year or until commodity prices markedly improve.

Dividend

In response to the continuing decline in commodity prices and in order to preserve capital and maintain future liquidity, the Company has suspended dividends under the Share Dividend Plan. Reinstatement of the dividend will depend on the timing and extent of the recovery in commodity prices.

Operating Margins and Funds from Operations

Commodity prices dropped in Q1 2016 to the lowest level experienced in years. As a result, Arsenal's Q1 2016 operating margin dropped by $2.3 million from Q4 2015 to total $1.5 million or $5.29 per Boe versus $3.8 million or $12.36 per Boe for Q4 2015 and dropped $2.8 million from $4.3 million or $11.74 per Boe from Q1 2015. Lower commodity prices, down by 28% in Q1 2016 from Q4 2015 and from Q1 2015 and lower production, down 8% from Q4 2015 and by 25% from Q1 2015 are responsible for the margin decrease.

For Q1 2016, Arsenal's funds used in operations dropped $2.8 million to ($262,583) or ($0.94) per Boe versus funds from operations of $2.5 million or $8.24 per Boe generated in Q4 2015 and dropped $16.0 million from Q1 2015 funds from operations of $15.8 million or $43.02 per Boe. Q1 2015 funds from operations included the monetization of the Company's crude commodity risk management contracts contributing $13.2 million or $35.91 per Boe to Q1 2015 funds from operations.

Production

Production for Q1 2016 averaged 3,058 Boe per day (81% crude oil and NGL and 19% natural gas) versus 3,338 Boe per day in Q4 2015 (81% crude oil and NGL and 19% natural gas) and 4,071 Boe per day in Q1 2015 (77% crude oil and NGL and 23% natural gas).

Average production was down 8% or 280 Boe per day from Q4 2015 and decreased in both Canada and the US. In Canada production was down due to natural production declines, due to uneconomic wells being shut-in and to production curtailments for required repairs and maintenance of facilities particularly at Desan. In the US, production was down as wells at Stanley and Lindahl in North Dakota experienced their natural and expected declines during the quarter and wells spud in Q1 2015 at Lindahl to replace declines had not commenced production.

Net Cash from (used in) Operating Activities

Net cash used in operating activities in Q1 2016 totaled ($226,277) versus funds generated in Q1 2015 of $17.1 million. Q1 2015 included crude hedging gains of $13.2 million. Reduced operating income in Q1 2016, changes in non-cash working capital and funds realized on the monetization of crude risk management contracts in Q1 2015 are largely responsible for these changes during the comparative periods.

Net Debt

At March 31, 2016, the Company's credit facility included a $30.0 million Extendable Syndicated Credit Facility, a $10.0 million Extendable Operating Credit Facility and a $14.0 million Supplemental Credit Facility (together the "Facility"). The Supplemental Credit Facility which was originally drawn at $15.0 million, was reduced by $1.0 million in the period and is required to be repaid by May 26, 2016. The Company currently does not have sufficient funds to repay this amount and is in negotiations with the lending syndicate to approve to a revised repayment schedule. Given additional time and with currently improved commodity prices, the Company is confident an agreement on repayment can be reached. The Supplemental Credit Facility bears a margin of 2% higher than the Extendable Syndicated Credit Facility. Proceeds from any common share equity issues (not including proceeds from the sale of flow-through shares) and from the sale of properties are required to be applied to reduce the Supplemental Facility.

Net debt at March 1, 2016 was $53.2 million, down from $53.8 million at December 31, 2015.

Net Debt Reconciliation

(000's Cdn. $)	**Three Months Ended March 31, 2016**
Net debt December 31, 2015	**53,816**
Funds required by operations	**263**
Additions to property, plant and equipment	**896**
Exploration and evaluation expenses	**149**
Decommissioning liabilities settled	**83**
Proceeds on sale of property	**(1,060)**
Foreign exchange loss (gain) on US cash held	**26**
Change in working capital and other items	**(1,003)**
Net debt March 31, 2016	**53,169**

Going Concern

The Company's credit facility is based on the bank's determination of the Company's borrowing base utilizing the Company's risked reserves and the lenders assessment of future commodity prices. The facility was scheduled for review on November 30, 2015 which concluded subsequent to year-end on January 8, 2016. As a result of the review, the Company's credit facility was reduced to a borrowing base of $40 million and a supplemental facility of $15 million (from $60 million - $55 million extendible facility and $5 million supplemental). The supplemental facility of $15 million ($14 million at March 31, 2016), has a maturity date of May 26, 2016. The extendible credit facility has a revolving period of 364 days plus one year and therefore has been classified as long-term. On review, the extendible facility can be increased or reduced. If increased it can be utilized to reduce the supplemental facility. If decreased the Company has 60 days to repay any shortfall and if not repaid, would represent an event of default under the credit facility. The next review of the credit facility is scheduled to be completed by May 26, 2016.

As the Company’s forecast of funds from operations is estimated to be insufficient to fully retire the supplemental facility by the maturity date, the Company has taken steps to sell all or a portion of its US properties and various non-core properties in Canada. In addition, the Company has deferred capital spending and initiated addition reductions in costs and expenses. While these steps have been initiated, there is no certainty that they will be successful, or that the funds generated will be sufficient to reduce the bank debt to an amount the Company can support with its retained assets.

Uncertainties exist as to the Company’s ability to continue as a going concern exist due to:

- A $14 million scheduled repayment of the supplemental facility on May 26, 2016. The Company does not currently have sufficient funds to repay this amount;
- On March 10, 2016, the Company applied for its annual extension of the Term Out Date noted in the extendible credit facility. Under the terms of the facility, the lenders have 30 days to respond and in the event such lenders do not respond within the 30 day period, the lenders shall be deemed to have advised the Company that it is not prepared to make an offer to the Company to extend its Term Out Date. The Company has not received any response to its March 10, 2016 request for extension either at the 30 day deadline or to date. If the Term Out Date is not extended, the Term Maturity Date of the facility is May 26, 2017 at which time the full balance will be due;
- There is uncertainty as to the determination of the borrowing base that will be provided by the lenders in May 2016. In the event the Company has a borrowing base shortfall and is unable to repay the amount within 60 days, this would represent an event of default under the credit facility which could result in all outstanding amounts being payable on demand;
- There is risk that the Company will not be able to comply with the financial covenant in 2016. Compliance is impacted by the undrawn debt which is at risk. In the event the Company has a covenant violation, this would represent an event of default under the credit facility which could result in all outstanding amounts being payable on demand; and
- The Company is committed to expend $2.0 million in 2016 on qualifying expenditures by December 31, 2016 to satisfy the requirements of the flow-through share issuance completed in 2015.

As a result of the above matters, there is a material uncertainty as to the Company’s ability to continue as a going concern.

Net Loss

The Company recorded a net loss in Q1 2016 of $5.8 million or $0.30 per share basic and diluted versus a loss of $466,316 or $0.03 per share basic and diluted in Q1 2015. Reduced operating income (revenue less royalties and operating and transportation expenses), a loss on foreign exchange and an increase in share-based compensation expense during the current quarter offset reduced exploration and evaluation expenses and lower depletion and depreciation expense.

Capital Expenditures

Capital expenditures on property, plant and equipment for Q1 2016 were curtailed to total $895,780 down from $6.7 million in Q1 2015. In Canada, the Company spent $224,019 in Q1 2016 versus $3.8 million in Q1 2015 and in the US, the Company spent $671,761 in Q1 2016 versus $2.9 million in Q1 2015. Expenditures in Canada were on land and on facilities at Princess and in the US were on wells and production facilities at Lindahl.

The Company did not expend any funds on exploration and evaluation assets in Q1 2016 or in Q1 2015.

Corporate Information

As of May 9, 2016, Arsenal has 19,422,976 common shares, 449,237 stock options and 320,998 share incentive (restricted and performance) awards 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 - OTCQX under the symbol "AEYIF".

In Canada, the Company operates under Arsenal Energy Inc. and had average production of 2,003 Boe per day for Q1 2016. In the US, the Company operates under its 100% indirectly owned subsidiary Arsenal Energy USA Inc. and had average production of 1,055 Boe per day for Q1 2016.

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, 2016. It should be read in conjunction with the audited consolidated financial statements and related notes of the Company for the year ended December 31, 2015. 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.

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 9, 2016.

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 this MD&A. 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 (“NGL”) in this MD&A include condensate, propane, butane and ethane and one barrel of NGL 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 (used in) operations”, “Funds from (used in) operations per share”, “Operating income”, “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.

Funds from (used in) operations is not recognized by IFRS but it is used by the Company, investors, analysts, bankers and others to evaluate and compare oil and gas exploration and producing entities. The Company determines funds from operations as net cash from operating activities before the net change in non-cash operating working capital, decommissioning obligations settled, exploration and evaluation expenses and transaction costs. The Company’s banker uses funds from operations (adjusted for the above and for interest and other financing charges) to measure debt to funds flow ratios that determine interest costs to the Company under its credit facility. The Company used funds from operations to analyze the Company’s performance and the ability of the Company to generate the cash flow necessary to fund dividends, growth through capital investment and to repay net 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 netback is funds from operations calculated on a Boe basis.

Operating income is calculated as revenue generated from oil and natural gas sales less royalties and operating and transportation expenses. Operating netback is operating income calculated on a 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.

Net debt includes bank borrowings, plus or minus working capital. Net debt <u>excludes</u> long term decommissioning obligations and risk management contracts (whether an asset or an obligation and whether classified as short or long term).

Net Cash (Used In) From Operating Activities and Funds (Used In) From Operations

The following table compares net cash (used in) from operating activities to funds (used in) from operations for Q1 2016 to Q1 2015:

	Three Months Ended March 31		
(000's Cdn. $)	**2016**	2015	% Change
Net cash (used in) from operating activities	**(227)**	17,109	(101)
Exploration and evaluation expenses	**149**	1,666	(91)
Decommissioning obligations settled	**83**	87	(5)
Change in non-cash working capital	**(268)**	(3,102)	(91)
Funds (used in) from operations	**(263)**	15,760	(102)

Net cash used in operating activities in Q1 2016 totaled $226,277 versus $17.1 million generated in Q1 2015. Net cash used in/from operating activities differs from the Company's calculation of funds (used in)/from operations due primarily to the Company's policy of expensing exploration and evaluation expenditures, the timing of incurring decommissioning expenditures and to the changes in non-cash working capital items.

Net cash from (used in) operating activities decreased by $17.3 million in Q1 2016 from Q1 2015 due primarily to lower realized gains in crude risk management contracts and from operating margins that dropped by $2.8 million in Q1 2016 due lower prices and lower production. Q1 2015 funds from operations included the monetization of the Company's crude commodity risk management contracts contributing $13.2 million to Q1 2015 funds from operations.

In Q1 2016, Arsenal's funds from operations dropped $16.0 million due to reasons noted above.

The following tables compares funds from operations by country and funds from operations per Boe for Q1 2016 to Q1 2015. These numbers are referred to throughout the MD&A:

Funds (Used In) From Operations By Country

	Three Months Ended March 31		
(000's Cdn. $)	**2016**	2015	% Change
Canada	**349**	13,707	(97)
US	**(612)**	2,053	(130)
Funds from (used in) operations	**(263)**	15,760	(102)

Funds (Used In) From Operations Per Boe

	Three Months Ended March 31		
($Cdn.)	**2016**	2015	% Change
Canada	**1.92**	59.16	(97)
US	**(6.37)**	15.25	(142)
Total	**(0.94)**	43.02	(102)

Past Eight Quarters

The following tables provide a comparison of the previous eight quarters of funds from operating activities to funds from operations, production, funds from operations by country, funds from operations before and after gains or losses on risk management contracts and funds from operations per Boe.

Funds (Used In) From Operations

	2016	2015				2014		
(000's Cdn. $)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Net cash (used in) from operating activities	**(227)**	1,728	6,155	2,405	17,109	25,392	17,628	6,619
Exploration and evaluation expenses	**149**	581	285	877	1,666	978	1,112	1,276
Decommissioning obligations settled	**83**	593	823	84	87	667	719	367
Change in non-cash working capital	**(268)**	(371)	(1,357)	2,793	(3,102)	(10,131)	(4,465)	3,348
Funds (used in) from operations	**(263)**	2,531	5,906	6,159	15,760	16,906	14,994	11,610

Production

	2016	2015				2014		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Oil and NGL (bbls/d)	**2,464**	2,716	2,828	2,925	3,129	3,701	3,857	3,386
Natural gas (mcf/d)	**3,559**	3,731	4,541	5,528	5,648	6,247	5,943	5,435
Total Boe	**278,239**	307,102	329,812	349.956	366,349	436,245	445,996	390,583
Boe per day	**3,058**	3,338	3,585	3.846	4,071	4,742	4,848	4,292

Production by Country

	2016	2015				2014		
(Boe per day)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Canada	**2,003**	2,168	2,380	2,481	2,574	2,990	2,950	2,765
US	**1,055**	1,170	1,205	1,365	1,497	1,752	1,898	1,527
Total	**3,058**	3,338	3,585	3,846	4,071	4,742	4,848	4,292

Funds (Used In) From Operations by Country

	2016	2015				2014		
(000's Cdn. $)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Canada	**349**	1,776	4,716	3,816	13,707	10,758	8,029	6,665
US	**(612)**	755	1,190	2,343	2,053	6,148	6,965	4,945
Total	**(263)**	2,531	5,906	6,159	15,760	16,906	14,994	11,610

Funds from Operations by Country per Boe

	2016	2015				2014		
(Cdn. $)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Canada	**1.92**	8.90	21.54	16.90	59.16	39.11	29.58	26.49
US	**(6.37)**	7.01	10.74	18.87	15.25	38.14	39.89	35.58
Total	**(0.94)**	8.24	17.91	17.60	43.02	38.75	33.62	29.72

Funds (Used In) From Operations

	2016	2015				2014		
(000's Cdn. $)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Before risk management contracts	**(192)**	2,531	4,042	6,221	2,632	10,528	16,351	13,860
Realized risk management contracts	**(71)**	-	1,864	(62)	13,128	6,378	(1,357)	(2,250)
After commodity contracts	**(263)**	2,531	5,906	6,159	15,760	16,906	14,994	11,610

Funds (Used In) From Operations Netback Per Boe

	2016	2015				2014		
(Cdn. $)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Before risk management contracts	**(0.69)**	8.24	12.26	17.78	7.18	24.13	36.66	35.49
After risk management contracts	**(0.94)**	8.24	17.91	17.60	43.02	38.75	33.62	29.73

The increases and decreases in the above periods for funds from operations relate primarily to drilling, uneconomic wells shut-in, changes to operating netbacks as a result of fluctuations in commodity prices, the timing of new low royalty rate production or higher rate freehold production, operating cost efficiencies and reductions, the disposition of high operating cost properties, changes in interest and financing charges and to the fluctuation in realized gains and losses from commodity risk management contracts. In addition, production from new high rate, high decline wells at Princess, Alberta and in the North Dakota Bakken impacts production and therefore funds from operations before commodity contracts.

In the past quarter, decreased production, lower commodity prices and changes in differentials offset by a lower Canadian dollar have combined to result in recent changes to Arsenal's funds from operations.

2016 FOCUS AND OUTLOOK

With WTI currently trading in the $35.00 US per barrel range and with differentials fluctuating, the ability to find and produce oil at a profit is challenging even with improved technology, reduced drilling and operating costs and a weaker Canadian dollar. Survival appears to be the mode for most oil and gas producers. Crude prices need to improve over the short and medium term to ensure a profitable and stable oil industry.

Oil prices have staged a modest recovery over the past 2 months. Operating netbacks or margins that averaged $5.29 per boe in Q1 2016 are estimated at approximately $13.00 per boe for Q2 2016. At these prices, Arsenal's Princess development delivers acceptable rates of return. In order to provide an acceptable return, Bakken drilling will require lower drilling costs or WTI prices to recover to the low US $60.00 level.

As previously announced, Arsenal has engaged a US based property broker to market all of the Company's US assets. That process is ongoing. There is strong interest in the properties but in the current environment of distressed asset sales and the ongoing volatility for oil prices, negotiations are proceeding more slowly than anticipated. Arsenal's borrowing facility is set to expire on May 25th. At that time, the $14 million non-conforming portion of Arsenal's facility comes due, and since it is anticipated that Arsenal will not have the cash at that time to satisfy the payment, Arsenal is working with its lenders on an amending agreement to allow the completion of the US sale process.

Production

Production for Q1 2016 averaged 3,058 Boe per day (81% crude oil and NGL and 19% natural gas) versus 3,338 Boe per day in Q4 2015 (81% crude oil and NGL and 19% natural gas) and 4,071 Boe per day in Q1 2015 (77% crude oil and NGL and 23% natural gas).

Average production for Q1 2016 was down 8% or 280 Boe per day from Q4 2015 and down 25% or 1,013 Boe per day from Q1 2015. Production decreased in both Canada and the US during Q1 2016 when compared to Q4 2015 and Q1 2015. In Canada production was down due to the sale of our Desan property in Q1 2016, natural production declines, to uneconomic wells being shut-in, due to production curtailments for required repairs and maintenance of facilities and to lack of development. In the US production was down as wells at Stanley and Lindahl in North Dakota experienced their normal decline during the quarter and wells recently drilled at Lindahl have not yet been put on full continued production.

Production Profile

Average Daily Production

	Three Months Ended March 31		
	2016	2015	% Change
Canada			
Heavy oil (bbls)	**4**	40	(90)
Medium oil and NGL's (bbls)	**1,495**	1,698	(12)
Natural gas (mcf)	**3,021**	5,019	(40)
Total Boe	**2,003**	2,574	(22)
US			
Light oil and NGL's (bbls)	**965**	1,392	(31)
Natural gas (mcf)	**537**	629	(15)
Total Boe	**1,055**	1,497	(30)
Corporate			
Heavy oil (bbls)	**4**	40	(90)
Oil and NGL's (bbls)	**2,461**	3,090	(20)
Natural gas (mcf)	**3,559**	5,648	(37)
Total Boe	**3,058**	**4,071**	(25)

By Commodity

	Three Months Ended March 31		
	2016	2015	% Change
Heavy oil	**-**	1%	-
Medium oil and NGL's	**49%**	42%	17
Light oil and NGLs	**32%**	34%	(8)
Natural gas	**19%**	23%	(16)

By Country

	Three Months Ended March 31		
	2016	2015	% Change
Canada	**65%**	63%	4
US	**35%**	37%	(6)

The percentage of production in Canada versus the percentage of production in the US may change in 2016 as a result of successful second half 2015 drilling at Princess, Alberta, based on the timing of wells waiting to be brought on full production at Lindahl and on the property sale initiatives being undertaken. Successful Princess wells drilled in 2015 will be tied-in and brought on production once prices and margins improve and production of 244 Boe/d in Q1 2016 at Desan was sold in mid-March 2016. Production from US drilling at Lindahl has not yet been fully brought on stream. Full production should offset production declines resulting in relatively flat US production period over comparative period.

Production by Area

	Three Months Ended March 31				
	2016		2015		
AREA	**Boe/d**	% of Total	Boe/d	% of Total	Change
Canada					
Galahad (light oil)	**88**	3	93	2	(5)
Princess (medium oil and gas)	**868**	28	923	23	(6)
Chauvin (medium oil and gas)	**245**	8	258	6	(5)
Provost (medium oil and gas)	**181**	6	311	9	(42)
Consort (medium oil and gas)	**61**	2	59	1	3
Evi (light oil)	**251**	8	212	5	18
BC Sold (Desan) (gas)	**244**	8	568	14	(57)
Others	**66**	2	150	3	(56)
Total Canada	**2,003**	65	2,574	63	(22)
US					
Stanley (light oil)	**690**	23	1,156	28	(40)
Lindahl (light oil)	**306**	10	281	7	9
Rennie Lake/Black Slough (light oil)	**42**	1	47	1	(11)
Lake Darling (light oil)	**16**	1	13	1	23
Total US	**1,055**	35	1,497	37	(30)
Total	**3,058**	100	4,071	100	(25)

Revenue

Prices - Before Commodity Contracts

	Three Months Ended March 31		
($Cdn.)	**2016**	2015	% Change
Canada			
Heavy oil per barrel	**40.10**	42.20	(5)
Medium oil and NGL's per barrel	**29.46**	41.16	(28)
Natural gas per mcf	**1.53**	2.22	(31)
Total per Boe	**24.38**	32.13	(24)
US			
Heavy oil per barrel	**-**	-	-
Light oil and NGL's per barrel	**34.31**	49.31	(30)
Natural gas per mcf	**2.33**	4.38	(47)
Total per Boe	**32.58**	47.69	(32)
Total			
Heavy oil per barrel	**40.10**	42.20	(5)
Oil and NGL's per barrel	**31.36**	44.83	(30)
Natural gas per mcf	**1.65**	2.46	(33)
Total per Boe	**27.21**	37.85	(28)

Reference Prices

	Three Months Ended March 31		
	2016	2015	% Change
WTI Cushing, Oklahoma ($U.S./bbl)	**33.45**	48.63	(31)
Canadian Light Sweet ($Cdn./bbl)	**41.22**	53.29	(23)
Hardisty Heavy 12 API ($Cdn./bbl)	**20.87**	38.65	(46)
Hardisty Bow River 24.9 API ($Cdn./bbl)	**26.63**	43.12	(38)
AECO (30 day spot) ($Cdn./MMBtu)	**1.83**	2.75	(33)
Henry Hub NYMEX Close ($U.S./MMBtu)	**1.99**	2.81	(29)
Foreign exchange ($Cdn./$U.S.)	**1.37**	1.24	11

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 generally reflective of the movement in commodity prices over the comparative periods.

In Canada, the Company received $29.46 per barrel for its medium oil and NGL in the current quarter, a decrease of 28% versus Q1 2015. This decrease is in line with the Company’s crude quality and market reference price changes. Hardisty Bow River stream (24.9 API), that is close to the Company’s medium quality crude in Canada, decreased 38% in Q1 2016 versus Q1 2015. In the US in Q1 2016, the price received for light oil decreased 30% to $34.31 per barrel. This approximates the 31% decrease in the price of WTI in the current quarter over the comparative quarter in 2015. The price received for natural gas decreased 31% in Canada and 47% in the US in Q1 2016 versus Q1 2015. The price received for natural gas in Canada generally tracks changes to the AECO price which was down 33% from Q1 2015 and in the US, the Henry Hub price was down 29% from Q1 2015.

The Company received an average price during Q1 2016 of $27.21 per Boe, a decrease of 28% from $37.85 per Boe received in Q1 2015. This decrease is attributed to the 31% decline, quarter over comparative quarter, in the price of WTI and a decrease in Q1 2016 from Q1 2015 in the price of natural gas in both Canada (AECO) and the US (Henry Hub) of 33% and 29% respectively.

Revenues

	Three Months Ended March 31		
(000's Cdn. $)	**2016**	2015	% Change
Canada			
Heavy oil	**14**	150	(91)
Medium oil and NGL's	**4,009**	6,291	(36)
Natural gas	**420**	1,002	(58)
Total	**4,442**	7,443	(40)
US			
Light oil and NGL's	**3,014**	6,175	(51)
Natural gas	**114**	248	(54)
Total	**3,128**	6,423	(51)
Total			
Heavy oil	**14**	150	(91)
Oil and NGL's	**7,023**	12,465	(44)
Natural gas	**533**	1,250	(57)
Oil and natural gas revenues	**7,570**	13,866	(45)
Gain (loss) on realized crude commodity contracts	**-**	13,154	(100)
Oil and gas revenue after realized crude commodity contracts	**7,570**	27,020	(72)
Revenue per boe before realized crude commodity contracts	**27.21**	37.85	(28)
revenue per boe after realized crude commodity contracts	**27.21**	73.75	(63)

Oil and natural gas revenues totaled $7.6 million for Q1 2016 a decrease of 45% over Q1 2015 due to a 28% decrease in the average price received per Boe and a 25% decrease in production. Average price received per Boe in Q1 2016 decreased $7.75 per boe in Canada and $15.11 per Boe in the US from Q1 2015.

Financial Instrument Contracts

Financial instrument or risk management 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.

In Q1 2015 and Q3 2015, the Company monetized all of its crude financial instrument contracts realizing a total gain of $15.1 million. For 2015, the Company recorded a net gain of $14.8 million on its financial instrument (commodity price and interest rate) contracts as a loss of $232,091 was a realized on the Company's interest rate swap financial contract.

Currently, the Company has the following crude commodity risk management contracts in place.

($Cdn. unless otherwise noted)			
Commodity Sold	Volume Sold	Remaining Term	Pricing
Oil	200 bbl per day	October 1, 2016 - December 31, 2016	$56.65 CAD per bbl
Oil	200 bbl per day	July 1, 2016 - September 30, 2016	$42.55 US per bbl
Oil	400 bbl per day	July 1, 2016 - September 30, 2016	$41.55 US per bbl
Oil	400 bbl per day	July 1, 2016 - September 30, 2016	$39.60 US per bbl

As at March 31, 2016, the Company has a crude commodity risk management asset recorded totaling $2,018 all of which is classified as an offset in current liabilities.

In order to mitigate the impact of future increases in interest rates, the Company entered into a swap contract fixing the base interest rate on $30 million of banker's acceptance with an expiry date of February 13, 2018. Terms of the Company's interest rate swaps are as follows:

Subject of Contract	Remaining Term	Notional Quantity	Reference	Strike Price	Option Traded
30 day BA rate	April 1, 2016 - February 13, 2018	$ 30,000,000	CAD - BA - CDOR	1.80%	Swap

As at March 31, 2016, the Company has an interest rate risk management liability recorded totaling $549,098 of which $299,508 is classified as a current liability.

The future asset or liability recorded changes with changes to interest rates.

Gains (Losses) on Risk Management Contracts

	Three Months Ended March 31		
(000's Cdn. $)	**2016**	2015	% Change
Realized gain (loss)			
Commodity	**-**	13,154	100
Interest rate	**(71)**	(26)	(171)
Total	**(71)**	13,128	101
Unrealized gain (loss)			
Commodity	**2**	(11,646)	100
Interest rate	**67**	(550)	112
Total	**69**	(12,196)	101
Total gain (loss)			
Commodity	**2**	1,508	100
Interest rate	**(4)**	(576)	99
Total risk management contracts	**(2)**	932	100
Per boe realized risk management contracts	**(0.26)**	35.84	101
Per boe unrealized risk management contracts	**0.25**	(33.29)	101
	(0.01)	2.54	100

Royalties

	Three Months Ended March 31		
(000's Cdn. $)	**2016**	2015	% Change
Canada			
Heavy oil	**1**	13	(95)
Medium oil and NGL's	**819**	1,775	(54)
Natural gas	**-**	11	(100)
Total	**819**	1,799	(54)
US			
Light oil and NGL's	**825**	1,722	(52)
Natural gas	**22**	47	(53)
Total	**847**	1,769	(52)
Total			
Heavy oil	**1**	13	(95)
Oil and NGL's	**1,644**	3,497	(53)
Natural gas	**23**	58	(61)
Royalties	**1,667**	3,569	(53)
Royalties per Boe	**5.99**	9.74	(39)

Percentage By Product

	Three Months Ended March 31		
	2016	2015	% Change
Heavy oil	**4**	9	(51)
Oil and NGL's	**23**	28	(17)
Natural gas	**4**	5	(9)
Total	**22**	26	(14)

Percentage By Country

	Three Months Ended March 31		
	2016	2015	% Change
Canada	**18**	24	(24)
US	**27**	28	(2)
Total	**22**	26	(14)

The Company's overall royalty rate for Q1 2016 averaged 22% compared to 26% for Q1 2015. Lower prices and lower well production have contributed to reduce royalty rates in Q1 2016 versus Q1 2015.

Looking forward, the corporate royalty rate on current production is expected to average in the 20% - 22% range. In Canada, the rate has fluctuated due to the timing of drilling low royalty rate wells and to some extent, commodity prices and production rates. In early 2016, the Alberta Government has announced a new royalty rate mechanism for 2017 and beyond that introduces a flat 5% royalty rate until payout (as defined) and an unannounced higher rate thereafter that will increase with higher commodity prices. This change will have an impact on future drilling plans and production in Alberta in 2017 and beyond. In the US due to the timing of production increases from higher royalty rate wells, 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. In the US, royalties are paid to freehold landowners and a production royalty (or tax) is paid to the State of North Dakota. The rates in the US are essentially fixed and are based on a percentage of revenue. As a result the rate does not change but the dollar value fluctuates with the fluctuation in commodity prices.

Operating and Transportation Expenses

	Three Months Ended March 31		
(000's Cdn. $)	**2016**	2015	**% Change**
Canada			
Heavy oil	**27**	161	(83)
Medium oil and NGL's	**2,446**	3,529	(31)
Natural gas	**866**	1,136	(24)
Total	**3,339**	4,826	(31)
US			
Light oil and NGL's	**1,073**	1,136	(6)
Natural gas	**19**	34	(44)
Total	**1,092**	1,170	(7)
Total			
Heavy oil	**27**	161	(83)
Oil and NGL's	**3,519**	4,665	(25)
Natural gas	**885**	1,171	(24)
Operating and transportation	**4,432**	5,997	(26)
Operating and transportation per Boe	**15.93**	16.37	(3)

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 decreased in Q1 2016 by $1.6 million or 26% from Q1 2015. On a Boe basis, operating costs decreased in Q1 2016 to $15.93 per boe from $16.37 per boe in Q1 2015. Current quarter operating costs decreased due to the sale of Desan, a general reduction in operating costs due to cost savings on electricity and to the electrification of some well sites, lower service costs, the shutting in of high cost uneconomic wells and general operational efficiencies.

Operating Netback per Boe

	Three Months Ended March 31			Three Months Ended March 31			
		2016			2015		Corporate
($Cdn.)	**Canada**	**US**	**Corporate**	Canada	US	Corporate	**% Change**
Heavy oil							
Revenue	**40.10**	**-**	**40.10**	42.20	-	42.20	**(5)**
Royalty	**(1.74)**	**-**	**(1.74)**	(3.75)	-	(3.75)	**(54)**
Operating and transportation	**(77.33)**	**-**	**(77.33)**	(45.20)	-	(45.20)	**71**
Operating netback per barrel	**(38.97)**	**-**	**(38.97)**	(6.75)	-	(6.75)	**478**
Medium and light oil and NGL's							
Revenue	**29.46**	**34.31**	**31.36**	41.16	49.31	44.83	**(30)**
Royalty	**(6.02)**	**(9.39)**	**(7.34)**	(11.61)	(13.75)	(12.58)	**(42)**
Operating and transportation	**(17.98)**	**(12.22)**	**(15.72)**	(23.09)	(9.07)	(16.78)	**(6)**
Operating netback per barrel	**5.47**	**12.70**	**8.31**	6.46	26.48	15.48	**(46)**
Natural gas							
Revenue	**1.53**	**2.33**	**1.65**	2.22	4.38	2.46	**(33)**
Royalty	**0.00**	**(0.46)**	**(0.07)**	(0.02)	(0.83)	(0.11)	**(39)**
Operating and transportation	**(3.15)**	**(0.39)**	**(2.73)**	(2.52)	(0.61)	(2.30)	**19**
Operating netback per mcf	**(1.62)**	**1.48**	**(1.16)**	(0.32)	2.94	0.04	**(2,891)**
Boe							
Revenue	**24.38**	**32.58**	**27.21**	32.13	47.69	37.85	**(28)**
Royalty	**(4.50)**	**(8.82)**	**(5.99)**	(7.77)	(13.14)	(9.74)	**(39)**
Operating and transportation	**(18.32)**	**(11.38)**	**(15.93)**	(20.83)	(8.69)	(16.37)	**(3)**
Operating netback per Boe	**1.56**	**12.38**	**5.29**	3.53	25.86	11.74	**(55)**

Canadian Netback

The Q1 2016 the operating netback from Canadian medium oil and NGL decreased $0.99 per barrel from Q1 2015. Lower average crude prices in 2016 were not entirely offset by lower operating expenses. The average price received decreased by 28% in the quarter while operating expenses decreased by 22% per barrel in the current quarter compared to Q1 2015.

The Q1 2016 operating netback from Canadian heavy oil production was a loss of $38.97 compared to a loss of $6.75 in Q1 2015. This production represents a very small portion of the Company's production and is being shut-in where possible until prices recover.

The Q1 2016 netback from Canadian natural gas decreased $1.30 per mcf to a loss of $1.62 per mcf from Q1 2015 due to lower prices that declined by 31% or $0.69 per mcf when compared to Q1 2015 and due to facility downtime resulting in lower volumes.

US Netback

The Q1 2016 netback from US light oil and NGL decreased $13.78 per barrel or 52% from Q1 2015. Lower crude prices, down 30% on a quarter over comparative quarter were responsible for this decline.

The Q1 2016 netback from the US natural gas decreased $1.46 per mcf or 50% from Q1 2015. These declines are due to lower prices that declined by 47% in the current quarter compared to Q1 2015.

Corporate Netback

Arsenal's Q1 2016 average price decreased $10.64 per Boe or 28% to $27.21 per Boe from $37.85 per Boe received in Q1 2015 resulting in a reduced netback of $6.45 per Boe to $5.29 per Boe in Q1 2016.

General and Administrative Expenses

	Three Months Ended December 31		
(000's Cdn. $)	**2016**	2015	% Change
Gross expenditures	**1,569**	1,762	(11)
Overhead recovery	**(305)**	(486)	(37)
Capitalized overhead	**(75)**	(175)	(57)
Net general and administrative expense	**1,189**	1,101	8
Gross general and administrative per boe	**5.64**	**4.81**	17
Net general and administrative per boe	**4.27**	3.01	42

Gross general and administrative expenditures were lower in Q1 2016 by $192,831 when compared to Q1 2015. On a net basis, general and administrative expenses increased in Q1 2016 over Q1 2015 by $87,815. Net expenditures were impacted by reduced overhead recoveries and capitalized overhead based on the decision to defer development and tie-ins, to deferring and cancelling some exploratory drilling plans and from the shut-in of certain uneconomic wells.

With the reduction in the Company's funds from operations expected in 2016 due to low commodity prices and lower production, the Company has continued certain cost reductions initiatives implemented in 2015. The Company continues to reduce staff levels, reduce work hours for certain employees and consultants and reevaluate the Company's benefit programs. This has resulted in increased severance costs in the short term but these initiatives are expected to result in lower gross expenditures and net expenses going forward.

On a Boe basis, gross general and administrative expenditures for the current quarter increased to $5.64 per Boe from $4.81 per Boe in Q1 2015. Net general and administrative expenses for the current quarter increased to $4.27 per Boe from $3.01 per Boe in Q1 2015. These increases are due primarily to lower production which is down 24% in the current quarter from Q1 2015 and lower overhead recoveries and overhead capitalized. In addition, Q1 2016 general and administrative expenditures include additional expenses related to staff reductions.

Exploration and Evaluation Expenses

	Three Months Ended March 31		
(000's Cdn. $)	**2016**	2015	% Change
Exploration and evaluation expenses	**149**	1,666	(91)
Per Boe	**0.54**	4.55	(88)

Arsenal expenses all pre-license costs, all seismic expenditures and all exploratory dry hole costs. Recoveries of these expenses are credited to exploration and evaluation expenses.

In Q1 2016, the Company incurred certain seismic expenditures related to its property at Princess, Alberta. In Q1 2015, the Company incurred certain seismic expenditures in Cessford and Princess, Alberta.

Interest and Other Financing Expenses

	Three Months Ended March 31		
(000's Cdn. $)	**2016**	2015	% Change
Interest and other financing charges	**612**	536	14
Per Boe	**2.20**	1.46	50

Interest and other financing charges include interest, bank charges and fees and other levies 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 increased 14% in Q1 2016 from Q1 2015 due primarily to higher fees and higher rates. For Q1 2016, the average daily borrowing balance was $52.7 million versus $52.4 million for Q1 2015. In Q1 2016, fees and interest charges averaged approximately 4.66% versus approximately 3.91% in Q1 2015.

Interest rates on the Operating Credit Facility range from Canadian or US prime plus 1.00% to 3.50% on prime based loans and on the Syndicated Credit Facility range from the base rate plus 2.00% to 4.50% on bankers' acceptances and on Libor based loans. The increment is determined based on the Company's debt to cash flow ratio as calculated under the provisions of the agreement. Interest rates on the Supplemental Credit Facility are 2% higher that on the Syndicated Credit Facility. Borrowings of $15.0 million on the Supplemental Credit Facility commenced on January 8, 2016. Since January, the Company has reduced the outstanding amount to $14.0 million (see disclosure under "Credit Facility" located below in this MD&A).

Depletion and Depreciation

	Three Months Ended March 31		
(000's Cdn. $)	**2016**	2015	% Change
Depletion and depreciation	**4,469**	**7,442**	(40)
Per boe	**16.06**	20.31	(21)

On an absolute dollar basis, depletion and depreciation in Q1 2016 decreased 40% from Q1 2015. This decrease is attributed to the recorded impairment in 2015 of $55.8 million, to a 25% decrease in average production, to a slightly increased reserve base in Canada and to lower future capital costs, particularly in Canada. On a Boe basis, depletion and depreciation decreased 21% to $16.06 per Boe in Q1 2016 versus $20.31 per Boe in Q1 2015.

In Canada, the depletion and depreciation rate decreased in Q1 2016 from $16.23 per Boe to $13.18 per Boe based on an increase in reserves (up 6.7%) at Princess, Chauvin/Ribstone and Desan, a decrease in the cost estimate to abandon and decommission wells, decreased future development costs and the 2015 impairment of Canadian CGU's.

In the US, the depreciation and depletion rate decreased in Q1 2016 from $27.34 per Boe Q1 2015 to $21.54 per Boe in 2015 due primarily to an impairment of the US CGU in 2015.

Accretion

	Three Months Ended March 31		
(000's Cdn. $)	**2016**	**2015**	% Change
Accretion	**241**	290	(17)
Per boe	**0.87**	0.79	9

Accretion is the increase, in the reporting period, in the present value of the Company's decommissioning liabilities. Accretion also includes additional expenditures incurred to decommission well sites and facilities over and above the estimate contained in the decommissioning liability provision.

Accretion for Q1 2016 decreased by 17% from Q1 2015 due primarily to lower expected costs to abandon and reclaim wells.

Share-based Compensation

	Three Months Ended March 31		
(000's Cdn. $)	**2016**	2015	% Change
Share-based compensation expense (recovery)	**170**	(988)	(117)
Per boe	**0.61**	**(2.70)**	(123)

The Company has a share option plan and a share award incentive plan. The Company discontinued any further grants of options under the share option plan. Options current outstanding will expire at the end of their respective terms in 2016, 2017 and 2018.

The Company has determined that, in certain circumstances, it will cash settle stock options and a portion of the Company's share awards. The remaining portion of the share awards are accounted for on an equity settled basis. As a result of changes to the Company's share price and vesting, the Company is required to revalue or re-measure the fair market value of the Company's incentive compensation liability at the end of each reporting period. The adjustment (up or down) to the liability is recorded in the statement of income. The equity adjustment for the share awards and the change in fair value of the Company's shares resulted in an expense to share-based compensation in the current quarter of $169,760 versus a recovery of $988,460 in Q1 2015... No share-based compensation has been capitalized during Q1 2016 or Q1 2015.

As no options are currently in-the-money, the Company has not recorded an incentive (share-based) compensation liability related to the cash settling of options as the option strike price and remaining term indicate that is unlikely the options will be exercised or cash settled. A liability of $93,100 related to the share award plan has been recorded as a current liability.

Foreign Exchange

	Three Months Ended March 31		
(000's Cdn. $)	**2016**	2015	% Change
Realized loss (gain)	**(138)**	(22)	(519)
Unrealized loss (gain)	**1,680**	(3,198)	153
Total foreign exchange loss (gain)	**1,542**	(3,220)	148
Per Boe realized loss (gain)	**(0.49)**	(0.06)	(715)
Per Boe unrealized loss (gain)	**6.04**	**(8.73)**	169
Per Boe total	**5.54**	(8.79)	163

Foreign exchange gains and losses are recognized based on the fluctuation of the Canadian and US dollar exchange rate and on the timing of the funding and repayment of funds advanced from the Company and its US operating subsidiary.

Sale of Properties

	Three Months Ended March 31		
(000's Cdn. $)	**2016**	2015	% Change
(Gain) on sale of property	**(126)**	**-**	-
Per boe	**(0.45)**	**-**	-

During Q1 2016, the Company sold its Desan property recording a gain on the sale of $126,336.

The Company will continue to sell properties, in whole or in part where the Company deems there to be no significant exploration or development upside, where operating costs are high or where the exposure to decommissioning liabilities can be cost effectively eliminated. Given the nature of the properties the Company is attempting to sell and the state of the current market for properties, it is possible that any future minor non-core property sales will result in minor accounting gains or losses for the Company.

Provision for Income Taxes

	Three Months Ended March 31		
(000's Cdn. $)	**2016**	**2015**	% Change
Current tax expense	**-**	**53**	(100)
Deferred tax expense (recovery)	**(998)**	**(1,182)**	(16)
Total	**(998)**	**(1,129)**	(12)
Per Boe - current	**-**	0.15	(100)
Per Boe - deferred	**(3.59)**	(3.23)	11
Per boe - Total	**(3.59)**	(3.08)	16

For Q1 2016, the Company has recorded income tax recovery of $997,530. In Canada, the loss before taxes for Q1 2016 was $4.0 million and in the US, the Q1 2016 loss before taxes was $2.7 million.

In Canada, the Company has not recorded any recovery of income tax as the Company has accumulated losses from Canadian operations and has estimated Canadian tax pools in excess of $85.0 million at December 31, 2015. The Company has recognized a portion of the premium related to the issuance of flow-through shares in 2015. The Company incurred flow-through expenditures in Q1 2016 of approximately $135,425 recognizing $13,173 of the recorded premium. The Company has a long-term liability (flow-through share issue premium) of $302,004 related to approximately $2.0 million of remaining qualifying expenditures required to be incurred by December 31, 2016.

In the US, the Q1 2016 loss before income taxes of $2.7 million resulted in a deferred income tax recovery totaling $984,357.

At March 31, 2016, the deferred tax liability recorded in the Company’s Statement of Financial Position of $3.2 million relates entirely to the US operations. The US deferred tax liability increases and decreases not only based on accounting income and loss but also due to increases and decreases in the Canadian/US exchange rate.

Net Income (Loss) per Boe

	Three Months Ended March 31	
($Cdn.)	**2016**	2015
Oil and gas revenue	27.21	37.85
Royalties	(5.99)	(9.74)
Operating and transportation	(15.93)	(16.37)
Operating netback per Boe	**5.29**	11.74
Realized gain (loss) on risk management contracts	(0.26)	35.84
Realized gain on foreign exchange	0.49	0.06
General and administrative	(4.27)	(3.01)
Interest and other financing charges	(2.20)	(1.46)
Current tax expense	-	(0.15)
Funds from operations netback per Boe	**(0.94)**	43.02
Unrealized gain (loss) on risk management contracts	0.25	(33.29)
Unrealized gain (loss) on foreign exchange	(6.04)	8.73
Depletion and depreciation	(16.06)	(20.31)
Accretion	(0.87)	(0.79)
Exploration and evaluation - directly expensed	(0.54)	(4.55)
Gain (loss) on sale of property and equipment	0.45	-
Share-based compensation	(0.61)	2.70
Deferred income tax	3.59	3.23
Net income (loss) per Boe	**(20.77)**	(1.27)

On a net income (loss) per Boe basis, the fluctuation in commodity prices not only affects the average Boe price received but can (as show in the above table) significantly create large swings in the recording of changes in the realized and unrealized portion of the Company's risk management contract positions. In addition, changes in the (Canadian/US) foreign exchange rates and impairment provisions for exploration and evaluation assets and property plant and equipment assets can result in large fluctuations in net income (loss) per Boe before income tax.

Net Cash (Used In) From Operating Activities,
Funds (Used In) From Operations and
Net Income (Loss)

	Three Months Ended March 31		
(000's Cdn. $ except per share amounts)	**2016**	2015	Change
Net cash from (used in) operating activities	**(227)**	17,109	(101)
Funds from (used in) operations	**(263)**	15,760	(102)
Per share			
Basic	**(0.01)**	0.88	(102)
Diluted	**(0.01)**	0.87	(102)
Net loss	**(5,779)**	(466)	1,139
Per share			
Basic	**(0.30)**	(0.03)	1,041
Diluted	**(0.30)**	(0.03)	1,057

Weighted Average Shares Outstanding

	Three Months Ended March 31		
(000's Cdn. $ except per share amounts)	**2016**	**2015**	Change
For Net (Loss) / Income Purposes			
Basic	19,423	17,884	9
Diluted	19,423	17,884	9
For Funds from Operations Purposes			
Basic	19,423	17,884	9
Diluted	19,744	18,126	9

Funds used in operations for Q1 2016 totaled ($262,583) ($0.01) per share basic and diluted) versus funds generated from operations in Q4 2015 of $2.5 million ($0.13 per share basic and diluted) and funds from operations in Q1 2015 of $15.8 million ($0.88 per share basic and $0.87 per share diluted). Lower commodity prices and lower production in Q1 2016 reduced operating income from Q4 2015 by $2.8 million. Lower prices and lower production in Q1 2016 reduced operating income from Q1 2015 by $2.8 million. Monetization of the Company's crude commodity risk management contracts in Q1 2015 added $13.2 million in Q1 2015 to funds from operations.

On a Boe basis, funds used in or required by operations in Q1 2016 was ($0.94) per Boe versus $8.24 per boe generated in Q4 2015 and $43.02 generated in Q1 2015.

Lower prices and lower production resulted in lower operating income that was offset by realized gains on crude commodity risk management contracts in Q1 2015.

The Company recorded a net loss in Q1 2016 of $5.8 million or $0.30 per share basic and diluted versus a loss of $466,316 or $0.03 per share basic and diluted in Q1 2015. During the current quarter, the Company's operating income dropped $2.8 million due to lower commodity prices that decreased 28% and to a 25% drop in Q1 2016 average production from Q1 2015. During Q1 2016, the Company recorded $1.2 million of additional share-based compensation and a loss on foreign exchange of $1.5 million versus a gain in Q1 2015 of $3.2 million. These items offset lower exploration and evaluation expenses and lower depreciation and depletion.

Comprehensive Income

The Company's comprehensive income (loss) includes unrealized foreign exchange gains and losses resulting from the translation into Canadian dollars of the Company's US subsidiary. The translation of the Company's US subsidiary into Canadian dollars resulted in a loss of $409,361 for Q1 2016 versus a gain of $3.0 million for Q1 2015. Comprehensive loss therefore for the three months ended March 31, 2016 was $6.2 million versus comprehensive income of $2.6 million for Q1 2015.

Summary of Quarterly Results

	2016	2015				2014		
(000's Cdn. $)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Production (Boe)								
Total	**278,239**	307,102	329,812	349,956	366,349	436,245	445,997	390,583
Per day	**3,058**	3,338	3,585	3,846	4,071	4,742	4,848	4,292
Oil and gas revenue	**7,570**	11,529	13,382	16,305	13,866	25,283	33,322	30,902
Funds (used in) from operations	**(263)**	2,531	5,906	6,159	15,760	16,906	14,995	11,610
Per share - basic ($)	**(0.01)**	0.13	0.31	0.34	0.88	0.98	0.89	0.72
- diluted ($)	**(0.01)**	0.13	0.30	0.34	0.87	0.95	0.88	0.71
Net income (loss)	**(5,779)**	(26,499)	(13,586)	(3,429)	(466)	15,367	9,622	(376)
Per share - basic ($)	**(0.30)**	(1.37)	(0.71)	(0.19)	(0.03)	0.89	0.57	(0.02)
- diluted ($)	**(0.30)**	(1.37)	(0.71)	(0.19)	(0.03)	0.81	0.57	(0.02)
Total assets	**149,013**	164,133	207,409	226,773	230,571	236,424	223,262	211,996
Total debt (1)	**53,169**	53,816	52,339	56,635	57,229	65,198	81,230	84,416
Shares outstanding	**19,423**	19,423	19,376	17,969	17,897	17,877	16,974	16,074

(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 commodity price and production swings, the changes in the posted differentials, the timing of drilling and completions particularly in the US and in Alberta at Princess, property impairments, the rationalization of properties and operating costs and in the past few quarters and to the shutting in of some oil and 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 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 increased 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 month Ended March 31, 2016 (000's Cdn. $)	Canada	U.S	Total
Production (Boe/d)	2,003	1,055	**3,058**
Oil and gas revenue	4,442	3,128	**7,570**
Operating income	283	1,188	**1,471**
Funds (used in) from operations	349	(612)	**(263)**
Loss before income taxes	(4,046)	(2,731)	**(6,777)**
Net loss for the year	(4,032)	(1,747)	**(5,779)**
Exploration and evaluation assets (as at March 31, 2016)	1,114	-	**1,114**
Property, plant and equipment (as at March 31, 2016)	85,037	57,620	**142,657**
Property, plant and equipment expenditures	224	672	**896**
Exploration and evaluation expenditures	-	-	**-**
Exploration and evaluation expenses	149	-	**149**
Property dispositions	(1,060)	-	**(1,060)**
Property acquisitions	-	-	**-**

For Three Months Ended March 31, 2015 (000's Cdn. $)	Canada	U.S	Total
Production (Boe/d)	2,574	1,497	**4,071**
Oil and gas revenue	7,443	6,423	**13,866**
Operating income	817	3,483	**4,300**
Funds from operations	13,707	2,053	**15,760**
Income (loss) before income taxes	30	(1,625)	**(1,595)**
Net income (loss) for the year	519	(985)	**(466)**
Exploration and evaluation assets (as at March 31, 2015)	3,639	-	**3,639**
Property, plant and equipment (as at March 31, 2015)	109,794	105,089	**214,883**
Property, plant and equipment expenditures	3,770	2,901	**6,671**
Exploration and evaluation expenditures	-	-	**-**
Exploration and evaluation expenses	1,666	-	**1,666**
Property dispositions	-	-	**-**
Property acquisitions	-	-	**-**

(1) Operating income is defined as revenue from oil and natural gas sales less royalties and operating and transportation expenses.

As the Company focuses its capital program on drilling at Princes, Alberta, it is expected that the Canadian operations will generate a more significant portion of the Company's production, revenues, and profits.

Liquidity and Capital Resources

Capital Management

The Company considers its capital structure to include working capital, its credit facility and shareholders' equity. The Company manages its capital base primarily on its net debt to annualized funds from operations ratio and its net debt to equity ratio. The Company continually monitors, through its annual budgeting and quarterly forecasting process, evaluates the risk reward profile of its exploration program and the economic returns of its 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 is required to repay $14.0 million due under its Supplemental Credit Facility by May 26, 2016 (see Credit Facility). In an attempt to generate repayment capacity, the Company has reduced its capital budget deferring development drilling and well tie-ins, reduced operating and general and administrative expenditures and hedged future production in an attempt to lock-in cash flow to contribute to lowering debt. In addition, the Company is also attempting to sell properties in both Canada and the US in an effort the meet this commitment. However, in this current low commodity price environment, properties for offered sale are being heavily discounted by potential buyers. Common equity has virtually disappeared at least until commodity prices show significant stability and improvement and if available would result in significant dilution. The Company is continuing to evaluate alternatives related to this repayment including on-going negotiations with the banking syndicate.

Net Debt and debt to Annualized Funds from Operations

(000's Cdn. $)	**March 31, 2016**
Bank loan	51,746
Working capital deficiency (1)	1,423
Net debt (2)	53,169
Annualized funds from operations (3)	9,000
Net debt to annualized funds flow ratio	**5.91**

(1) Working capital is calculated as current assets minus current liabilities adjusted for the value of risk management contracts whether a current asset or a current liability and for bank borrowing classified as a current liability that I is included under "bank loan". The Company maintains sufficient unused bank credit facility to ensure any working capital deficiency can be funded.

(2) Net debt includes bank borrowings, plus or minus working capital and excludes long term decommissioning obligations and risk management contracts (whether current or long term and whether an asset or an obligation).

(3) Annualized funds from operations is calculated as net cash from operating activities, before changes in non-cash working capital, decommissioning obligations settled, exploration and evaluation expenses and transaction costs from the Company's most recent quarter multiplied by four, adjusted, if required, for large one-time items included in the recent quarter and significant forecasted changes to production and commodity prices.

The Company's net debt to annualized funds from operations ratio at December 31, 2015 is 5.91 : 1.

The Company's net debt to equity ratio at December 31, 2015 is 1.07: 1.

These ratios are unacceptable and unsustainable and must be reduced by increased cash flow from higher prices and lower costs or by lowering debt or raising common equity. Equity markets may be available to reduce debt but the dilution to existing shareholders would be significant. Management is evaluating all alternatives.

Net Debt Reconciliation

(000's Cdn. $)	Three Months Ended March 31, 2016
Net debt December 31, 2015	**53,816**
Funds required by operations	**263**
Additions to property, plant and equipment	**896**
Exploration and evaluation expenses	**149**
Decommissioning liabilities settled	**83**
Proceeds on sale of property	**(1,060)**
Foreign exchange loss (gain) on US cash held	**26**
Change in working capital and other items	**(1,003)**
Net debt March 31, 2016	**53,169**

Debt to Equity Ratio

Net debt to annualized funds flow ratio	March 31, 2016

(000's Cdn. $)	March 31, 2016
Shareholders' Equity	49,700
Debt to equity	**1.07**

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

The Company has not adjusted its approach to capital management during 2015.

Credit Facility

In January 2016, the Company's credit facility consisted of a $30.0 million Extendable Syndicated Credit Facility, a $10.0 million Extendable Operating Credit Facility and a $15.0 million Supplemental Credit Facility (together the "Facility"). Borrowings under the Company's Extendible Credit Facility are available in prime based loans in either Canadian or US dollars, bankers' acceptances and London InterBank Offered Rate ("LIBOR") loans.

The Supplemental Credit Facility, available by way of a single advance on the effective date, was drawn in January at $15.0 million, has been reduced to $14 million and is required to be repaid by May 26, 2016. The Supplemental Credit Facility bears a margin of 2% higher than the Extendable Syndicated Credit Facility. As the Supplemental Credit Facility has a maturity date of May 26, 2016, the amount has been classified as a current liability at March 31, 2016. Proceeds from any common share equity issues (not including proceeds from the sale of flow-through shares) and from the sale of properties are required to be applied to reduce the Supplemental Credit Facility.

Interest rates on the Extendable Operating Credit Facility and on prime based loans range from Canadian or US prime plus 1.00% to 4.50%. Bankers' acceptances and LIBOR borrowings are subject to base borrowing rates plus additional stamping fees ranging from 2.00% to 4.50. The stamping fees and margins for the Supplemental Facility are at a rate of 2.00% higher than the corresponding rate for the Extendible Credit Facility. The stamping fees and margins are dependent on the debt to cash flow ratio, as defined, and as calculated based on the Company's two most recent quarter ends.

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 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 and to not make distributions (defined to include dividends and purchases under a normal course issuer bid).

The Company's 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 and any current drawings on the Supplemental Credit Facility) to fall to below 1 : 1.

At March 31, 2016, the Company was in compliance with this and all other covenants as required under the agreement.

At March 31, 2016, debt under the Facility amounted to $51.7 million (December 31, 2015 - $52.5 million) of which $14.0 million was outstanding under the Supplemental Credit Facility. Net debt (after adjusting for working capital deficiency at March 31, 2016 was $53.2 million (December 31, 2015 - $53.8 million).

Liquidity

Over the course of the past 24 months, there has been a severe and rapid decline in the price of crude and natural gas. While crude prices have recovered somewhat in the past month, commodity prices in Q1 2016 were the lowest the Company has experienced. As a result of production being greater that demand, the inventory of crude, crude bi-products and natural gas, are not only increasing but are threatening and sustained price recovery. Lower prices and a slower recovery has in turn resulted in reductions in the Company's borrowing base. A reduced borrowing base in combination with lower prices has recalibrated economics and has affected the ability of the Company to continue funding capital projects. Debt repayment, cutbacks and survival is the focus of most oil and gas companies these days. Arsenal has and will continue to shut-in uneconomic wells at the expense of production, cut overhead and operating costs to become more efficient, defer drilling and tie-ins until operating margins become acceptable and continue to reduce all expenditures. The Company has entered into a process to sell non-core properties in Canada and the US to reduce debt. While these initiatives are steps in the right direction, none in and of themselves guarantee long-term survival in a continued depressed commodity market. Prices need to improve for not only Arsenal but for the industry to survive.

Going Concern

The Company's credit facility is based on the bank's determination of the Company's borrowing base utilizing the Company's risked reserves and the lenders assessment of future commodity prices. The facility was scheduled for review on November 30, 2015 which concluded subsequent to year-end on January 8, 2016. As a result of the review, the Company's credit facility was reduced to a borrowing base of $40 million and a supplemental facility of $15 million (from $60 million - $55 million extendible facility and $5 million supplemental). The supplemental facility of $15 million ($14 million at March 31, 2016), has a maturity date of May 26, 2016. The extendible credit facility has a revolving period of 364 days plus one year and therefore has been classified as long-term. On review, the extendible facility can be increased or reduced. If increased it can be utilized to reduce the supplemental facility. If decreased the Company has 60 days to repay any shortfall and if not repaid, would represent an event of default under the credit facility. The next review of the credit facility is scheduled to be completed by May 26, 2016.

As the Company's forecast of funds from operations is estimated to be insufficient to fully retire the supplemental facility by the maturity date, the Company has taken steps to sell all or a portion of its US properties and various non-core properties in Canada. In addition, the Company has deferred capital spending and initiated addition reductions in costs and expenses. While these steps have been initiated, there is no certainty that they will be successful, or that the funds generated will be sufficient to reduce the bank debt to an amount the Company can support with its retained assets.

Uncertainties exist as to the Company's ability to continue as a going concern exist due to:

- A $14 million scheduled repayment of the supplemental facility on May 26, 2016. The Company does not currently have sufficient funds to repay this amount;
- On March 10, 2016, the Company applied for its annual extension of the Term Out Date noted in the extendible credit facility. Under the terms of the facility, the lenders have 30 days to respond and in the event such lenders do not respond within the 30 day period, the lenders shall be deemed to have advised the Company that it is not prepared to make an offer to the Company to extend its Term Out Date. The Company has not received any response to its March 10, 2016 request for extension either at the 30 day deadline or to date. If the Term Out Date is not extended, the Term Maturity Date of the facility is May 26, 2017 at which time the full balance will be due;
- There is uncertainty as to the determination of the borrowing base that will be provided by the lenders in May 2016. In the event the Company has a borrowing base shortfall and is unable to repay the amount within 60 days, this would represent an event of default under the credit facility which could result in all outstanding amounts being payable on demand;
- There is risk that the Company will not be able to comply with the financial covenant in 2016. Compliance is impacted by the undrawn debt which is at risk. In the event the Company has a covenant violation, this would represent an event of default under the credit facility which could result in all outstanding amounts being payable on demand; and
- The Company is committed to expend $2.0 million in 2016 on qualifying expenditures by December 31, 2016 to satisfy the requirements of the flow-through share issuance completed in 2015.

As a result of the above matters, there is a material uncertainty as to the Company's ability to continue as a going concern.

Dividends

In January 2016, given the Company's financial position and the current low crude and natural gas prices, the Company suspended its dividend payments.

Since the inception of the dividend plan August 2013, the Company has returned $8.0 million to shareholders in the form of cash and common shares.

Dividend History

Year	Declaration Date	Record Date	Payment Date	Dividend Per Common Share Cdn. $	Common Shares Outstanding	Total Value Returned To Shareholders Cdn. $	Cash	Shares Issued
2013	August 7	August 15	August 30	0.060	16,069,586	964,175	964,175	-
	November 6	November 15	November 29	0.060	16,069,586	964,175	964,175	-
2014	February 11	February 21	February 28	0.060	16,090,119	965,407	965,407	-
	May 6	May 16	May 30	0.065	16,074,419	1,044,838	1,044,838	-
	August 6	August 18	August 28	0.070	16,886,485	1,182,054	966,209	21,044
	November 4	November 14	November 28	0.070	16,938,028	1,185,661	1,013,684	21,294
2015	February 9	February 17	February 27	0.030	17,877,272	536,318	465,325	19,489
	May 4	May 15	May 29	0.020	17,896,761	357,935	309,716	12,708
	August 4	August 14	August 28	0.020	19,332,706	386,687	319,201	67,486
	November 2	November 13	November 27	0.020	19,375,680	387,515	323,929	63,586

Share Capital

Common Shares

	Three Months Ended March 31, 2016		Year Ended December 31, 2015	
(000's)	**Shares**	**$**	Shares	$
Balance - beginning of period	**19,423**	**155,988**	**17,877**	151434
Issued under private placements	**-**	**-**	**1,364**	**4,619**
Share issue costs	**-**	**-**	**-**	**(713)**
Issued pursuant to share dividend program	**-**	**-**	**122**	**250**
Issued on vesting of Share Award Incentive Plan	**-**	**-**	**60**	**398**
Balance - end of period	**19,423**	**155,988**	19,423	155,988

In 2015, the Company issued 122,085 common shares in relation to the share dividend program.

Options

(000's)	**Three Months Ended March 31, 2016**	Year Ended December 31, 2015
Balance - beginning of period	**618**	1,014
Exercised	**-**	-
Option "puts" cash settled by the Company	**-**	-
Cancelled (forfeited or expired unexerecised)	**(118)**	(396)
Balance - end of period	**500**	618

In May 2014, the Company implemented a Share Award Incentive Plan and discontinued any further grants of options under the option plan. All current outstanding options will expire at the end of their respective term.

Share Awards Incentive Plan

	Three Months Ended March 31, 2016		**Year Ended December 31, 2015**	
(000's)	**Restricted**	**Performance**	**Restricted**	**Performance**
Balance - beginning of period	**189**	**175**	127	115
Awards isued	-	-	**124**	**117**
Cancelled (forfeited or expired unexerecised)	**(10)**	**(12)**	**(22)**	**(22)**
Adjustment for dividends	-	-	**1**	**1**
Adjustment for performance factor	-	-	-	**20**
Vested and converted into common shares	-	-	**(25)**	**(35)**
Vested and paid in cash	-	-	**(16)**	**(21)**
Balance - end of period	**179**	**163**	189	175

Under the share award incentive plan, the Company may issue restricted awards and/or performance awards. Restricted awards entitle the participant to one common share of the Company for each restricted award issued. Performance awards entitle the participant to common shares of the Company based on a payout multiple based on pre-determined corporate performance measures of from 0 times to 2 times the number of performance awards issued. The Company has determined that payment under the share award incentive plan will be partially in common shares and partially in cash and has accounted for these awards as both equity settled and as liability settled and has estimated a performance payout of 1 on the performance awards.

The payout multiplier for the performance awards issued on June 19, 2014 was calculated at 1.5 based on the Company's ranking in the 2nd quartile based on overall shareholder return versus a peer group. The Company issued a total of 59,460 common shares (valued at $328,435 - $3.42 per share) under the Share Incentive Award Plan and remitted $125,351 to Canada Revenue Agency representing the tax liability to participants on the benefit of the awards.

On June 18, 2015, the Company issued an additional 123,700 restricted awards and 117,300 performance awards to directors, officers and employees.

At December 31, 2015, the Company has 19,422,976 common shares outstanding, 617,837 options outstanding at a weighted average price of $5.70 per share of which 537,997 are exercisable at a weighted average strike price of $5.95 and 188,699 restricted share rights and 174,966 performance share rights outstanding under the Share Award Incentive Plan.

As of the date of this MD&A, the Company has 19,422,976 common shares outstanding, 500,237 options outstanding and 178,699 restricted share award and 163,299 performance share award outstanding.

Capital Expenditures

Capital expenditures for Q1 2016 to property, plant and equipment totaled $895,780 down from $6.7 million in Q1 2015. Liquidity issues and reduced commodity prices resulting in reduced margins that have affected the economics of drilling have impacted the ability of the Company to raise equity or its decision to reinvest cash flow. Expenditures of $224,019 in Canada in Q4 2015 down from $3.8 million in Q1 2015 were incurred to purchase land and complete wells at Princess. In the US, expenditures accrued in Q1 2016 of $671,761 were spend on wells drilled in Q1 2015 at Lindahl. In Q1 2015, the Company spent $2.9 million on drilling these wells.

During Q1 2016, the Company disposed of its Desan property in BC for proceeds of $1.1 million.

Net Wells Drilled

	Three Months Ended March 31	
	2016	**2015**
Net wells drilled - Oil	**-**	0.89
- Gas	**-**	-
- Dry and other	**-**	-
Total net wells drilled	**-**	0.89

Expenditures

Total Company

Property, Plant and Equipment Expenditures

	Three Months Ended March 31,	
(000's Cdn. $)	**2016**	**2015**
Land	**82**	312
Drilling and completions	**679**	3,802
Capitalized general and administrative	**75**	175
Production equipment, facilities and tie-ins	**60**	2,382
Other	**136**	566
Total property plant and equipment additions	**1,032**	7,237
Non-cash additions	**(136)**	(566)
Total Property, Plant and Equipment Expenditures	**896**	6,671

Property Dispositions

(000's Cdn. $)	Three Months Ended March 31, 2016	2015
Total Property Dispositions	**(1,060)**	-

Exploration and Seismic Expenses

(000's Cdn. $)	Three Months Ended March 31, 2016	2015
Seismic expenditures	**149**	1,666
Proceeds on sale of seismic	**-**	-
Total Exploration and Seismic Expenses	**149**	1,666

CANADA

Property, Plant and Equipment Expenditures

(000's Cdn. $)	Three Months Ended March 31, 2016	2015
Land	**82**	209
Drilling and completions	**66**	1,424
Capitalized general and administrative	**75**	175
Production equipment, facilities and tie-ins	**1**	1,962
Other	**136**	559
Total property plant and equipment additions	**360**	4,329
Non-cash additions	**(136)**	(559)
Total Property, Plant and Equipment Expenditures	**224**	3,770

Property Dispositions

(000's Cdn. $)	Three Months Ended March 31, 2016	2015
Total Property Dispositions	**(1,060)**	-

Exploration and Seismic Expenses

(000's Cdn. $)	Three Months Ended March 31, 2016	2015
Seismic expenditures	**149**	**1,666**
Proceeds on sale of seismic	**-**	**-**
Total Exploration and Seismic Expenses	**149**	1,666

USA

Property, Plant and Equipment Expenditures

	Three Months Ended March 31,	
(000's Cdn. $)	**2016**	**2015**
Land	**-**	103
Drilling and completions	**613**	2,378
Capitalized general and administrative	**-**	-
Production equipment, facilities and tie-ins	**59**	420
Other	**-**	7
Total property plant and equipment additions	**672**	2,908
Non-cash additions	**-**	(7)
Total Property, Plant and Equipment Expenditures	**672**	2,901

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, 2015**	Year Ended December 31, 2015
Total decommissioning obligations at beginning of year	**40,350**	44,729
Obligations settled	**(83)**	(1,587)
Obligations disposed of on property sales	**(2,894)**	(462)
Obligations incurred	**136**	619
Change in estimate	**-**	(5,328)
Foreign currency translation	**(432)**	1,271
Accretion expense	**241**	1,108
Total decommissioning obligations at end of period	**37,318**	40,350
Recorded as folows:		
Decommissioning obligations to be incurred within one year	**300**	300
Decommissioning obligations to be incurred beyond one year	**37,018**	40,050
Total decommissioning obligations at end of period	**37,318**	40,350

Commitments and Contingencies

Contractual Obligations

In the ordinary course of business, the Company enters into various contractual obligations, including the following:

- purchase of services
- royalty agreements
- operating agreements
- transporting, processing and treating agreements
- right-of-way and road use agreements
- lease obligations for office space, office equipment and automotive equipment
- flow-through share expenditure agreements
- banking agreement
- hedging contracts

All such contractual obligations reflect market conditions at the time of contract and do not involve related parties.

Outstanding lawsuits

Various lawsuits have been filed against the Company for incidents which arose in the ordinary course of business. In the opinion of management and legal counsel, the outcome of the lawsuits, now pending, are not material to the Company's operations. Management has, however, made provision in the financial statements for the potential of such loss. Should any loss, in excess of the provision estimated result from the resolution of these claims, such loss will be charged to operations in the period of resolution.

Future Accounting Policies and Changes:

The International Accounting Standards Board (the "IASB") has issued new standards and amendments to existing standards that have been issued but are not yet effective. The following may have an impact on the Company's consolidated financial statements. The impact, if any, has not been determined.

Leases

In January 216, the IASB issued IFRS 16 Leases, which requires lessees to recognize assets and liabilities for most leases. The standard replaces ISA17 and will be effective for annual periods beginning on or after January 1, 2019.

Financial Instruments

IFRS 9 Financial Instruments is intended to replace IAS 39 Financial Instruments: recognition and Measurement and uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, and also requires a single impairment method to be used, replacing the multiple rules of IAS 39. Although new hedge accounting requirements have been introduced, Arsenal does not employ hedge accounting for risk management contracts. The standard is effective for annual periods beginning on or after January 1, 2018.

Revenue

In May 2014, the IASB issued IRS 15 Revenue from Contracts with Customers which replaces IAS18 and IAS11. The standard is required to be adopted for fiscal years beginning on or after January 1, 2018.

Disclosure Controls and Procedures

There were no changes in disclosure controls and procedures during the interim period commencing January 1, 2016 and ending March 31, 2016...

Internal Controls over Financial Reporting

The Chief Executive Officer and Chief Financial Officer of Arsenal are responsible for designing internal controls over financial reporting or causing them to be designed and providing supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Utilizing the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") Internal Control – Integrated Framework (2013), Arsenal's management has evaluated, or caused to be evaluated under their supervision, the design and effectiveness of internal controls over financial reporting.

While Arsenal's Chief Executive Officer and Chief Financial Officer believe the Company's internal controls and procedures provide a reasonable level of assurance that they are reliable, an internal control system cannot prevent all errors and fraud. It is management's belief that any control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

During the design assessment certain material weaknesses in internal controls over financial reporting were identified, as follows:

• Management is aware that there is a lack of segregation of duties due to the small number of employees dealing with general administrative and financial matters. However, management believes that at this time the potential benefits of adding employees to clearly segregate duties do not justify the costs associated with such increase;

• Many of Arsenal's information systems are subject to general control deficiencies including a lack of effective controls over spreadsheets, access and documentation. The Company expects that these deficiencies will continue into the future; and

• Arsenal does not have full-time in-house personnel to address all complex and non-routine financial and tax issues that may arise. It is not deemed as economically feasible at this time to have such personnel. Arsenal relies on external experts for review and advice on complicated financial and tax issues and for tax planning, tax provision and compilation of corporate tax returns.

These weaknesses in internal controls over financial reporting result in a more than remote likelihood that a material misstatement would not be prevented or detected. Management and the Board of Directors work to mitigate the risk of material misstatement; however, management and the Board do not have reasonable assurance that this risk can be reduced to a remote likelihood of a material misstatement. There were no changes in internal controls over financial reporting during the interim period commencing January 1, 2016 and ending March 31, 2016.