MANAGEMENT DISCUSSION AND ANALYSIS

SUMMARY OF FINANCIAL AND OPERATIONAL RESULTS				
	Three Months Ended June 30		**Six Months Ended June 30**	
(000'S Cdn. $ except per share amounts)	**2015**	**2014**	**2015**	2014
FINANCIAL				
Oil and gas revenue	**16,305**	30,902	**30,171**	58,508
Cash provided by operation activities	**2,405**	6,619	**19,514**	14,248
Funds from operations	**6,159**	11,610	**21,919**	**22,663**
Per share - basic	**0.34**	0.72	**1.22**	1.41
Per share - diluted	**0.34**	0.71	**1.20**	1.39
Cash and stock dividends paid	**358**	1,045	**894**	2,010
Net income (loss)	**(3,429)**	(376)	**(3,895)**	652
Per share - basic	**(0.19)**	(0.02)	**(0.22)**	0.04
Per share - diluted	**(0.19)**	(0.02)	**(0.22)**	0.04
Total debt	**56,635**	84,416	**56,635**	84,416
Capital expenditures	**6,035**	17,451	**12,706**	29,640
Property acquisitions	-	**-**	**-**	152
Property dispositions	**(1,677)**	-	**(1,677)**	-
Net wells drilled - Oil	**-**	3.16	**0.89**	7.76
- Dry and other	**-**	1.20	**-**	1.20
Total net wells drilled	**-**	4.36	**0.89**	8.96
Common Share Trading Range				
High	**5.60**	8.70	**6.72**	8.70
Low	**3.00**	6.40	**3.00**	4.52
Close	**3.13**	7.84	**3.13**	7.84
Average daily volume	**15,189**	22,870	**17,177**	22,133
Shares outstanding - end of period	**17,969**	16,074	**17,969**	16,074
OPERATIONAL				
Daily production				
Heavy oil (bbl/d)	**18**	36	**29**	41
Medium oil and NGL's (bbl/d)	**1,636**	1,912	**1,667**	1,774
Light oil and NGLs (bbl/d)	**1,271**	1,438	**1,331**	1,368
Natural gas (mcf/d)	**5,528**	5,435	**5,587**	6,102
Oil equivalent (boe/d @ 6:1)	**3,846**	4,292	**3,957**	4,201
Realized commodity prices ($Cdn.)				
Heavy oil (bbl)	**45.32**	87.94	**43.17**	78.85
Medium oil and NGL's (bbl)	**57.37**	89.93	**49.16**	88.17
Light oil and NGLs (bbl)	**56.74**	96.56	**52.88**	96.58
Natural gas (mcf)	**2.25**	4.71	**2.35**	5.15
Oil equivalent (boe @ 6:1)	**46.59**	79.12	**42.12**	76.95
Netback ($ per boe)				
Revenue	**46.59**	79.12	**42.12**	76.95
Royalty	**(8.90)**	(17.54)	**(9.33)**	(16.14)
Operating and transportation	**(14.50)**	(20.89)	**(15.46)**	(21.09)
Operating netback per boe	**23.19**	40.69	**17.33**	39.72
General and administrative	**(3.28)**	(2.94)	**(3.14)**	(2.81)
Cash portion of share based compensation	**(0.36)**	-	**(0.17)**	-
Interest and other financing	**(1.49)**	(1.80)	**(1.48)**	(1.80)
Realized gain (loss) on risk management contracts	**(0.18)**	(5.76)	**18.24**	(4.99)
Other (FX and current tax)	**(0.28)**	(0.46)	**(0.18)**	(0.32)
Fund from operations per Boe	**17.60**	29.72	**30.60**	29.81

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

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

Q2 2015 Financial and Operating Highlights

As a result of the severe drop in crude prices that started in Q4 2014, the Company, in early 2015, undertook certain initiatives to maintain its financial strength and preserve balance sheet flexibility. These initiatives included reducing the dividend, lowering the Company's capital budget, deferring development drilling and focusing on the Company's exploration program (in order to bolster and improve the Company's development inventory for when prices and margins improve), reducing bonuses for employees, lowering director fees and freezing employee salaries. Since then, the Company has undertaken numerous additional actions to lower its cost structure such as eliminating several head office positions, limiting the use of consultants, undertaken an proactive approach to reducing operating costs and reviewed and reduced other general and administrative expenses. The end result of these initiatives has been to reduce capital spending from $53.5 million in 2014 to an estimated $27.0 million in 2015, to achieve a reduction in operating costs of approximately 23% from $30.1 million in 2014 to an estimated $23.2 million in 2014 and to lower ongoing general and administrative expenditures.

Dividends

On August 4, 2015, the Board of Directors declared a quarterly dividend of $0.02 per common share to be paid on August 28, 2015 to shareholders of record on August 14, 2015. To date, dividends declared in 2015 will have returned approximately $1.3 million in cash or in common shares of Arsenal to shareholders who participate in the Share Dividend Plan.

Shareholders wishing to participate in the Share Dividend Plan should contact their broker or intermediary or, in the case of registered shareholders, contact our transfer agent, Alliance Trust Company, or visit our website to obtain the necessary enrolment forms.

Funds from Operations

For Q2 2015, funds from operations dropped $5.5 million to total $6.1 million or $17.60 per Boe versus $11.6 million or $29.72 per Boe for Q2 2014. For the six months ended June 30, 2015, funds from operations declined by $743,632 when compared to the 2014 six month period. Lower commodity prices, down by 41% in Q2 2015 from Q2 2014 and by 45% for the 2015 six month period versus the 2015 six month period, reduced operating margins by $7.8 million quarter over comparative quarter and by $17.9 million from the comparative six month period. For the six month period, funds from operations decreased 3% as the reduced operating margin was offset by a realized gain, in Q1 2015, on the monetization of commodity risk management contracts resulting in an increase in the funds from operations netback per Boe by $18.24 per Boe versus a loss in 2014 of $4.99 per Boe. Other cash costs in the quarter and in the six month period were in total generally comparable.

Operating Netback

The operating netback for Q2 2015 dropped 43% to $23.19 per Boe versus $40.69 per Boe in Q2 2014 and for the 2015 six month period dropped 56% to $17.33 per Boe versus $39.72 per Boe. The average price received dropped 41% or $32.53 per Boe in Q2 2015 from Q2 2014 and by $34.83 per Boe or 45% in the current six month period versus the 2014 six month period.

Net Cash from Operating Activities

Net cash from operating activities in Q2 2015 totaled $2.4 million versus $6.6 million generated in Q2 2014 and for the six month ended June 30, 2015 totaled $19.5 million versus $14.2 million for the 2014 six month period. Changes in operating margins, exploration and evaluation expenses, funds realized on crude risk management contracts and foreign exchange and changes in non-cash working capital are largely responsible for these changes during the respective comparative periods.

Production

Production for Q2 2015 averaged 3,846 Boe per day (76% crude oil and NGL and 24% natural gas) versus 4,071 Boe per day in Q1 2015 (77% crude oil and NGL and 23% natural gas) and 4,292 Boe per day in Q2 2014 (79% crude oil and NGL and 21% natural gas). For the six months ended June 30, 2015, production averaged 3,957 Boe per day (76% crude oil and NGL and 24% natural gas) versus 4,201 Boe per day (76% crude oil and NGL and 24% natural gas) for the six months ended June 30, 2014.

Average production was down 6% from Q1 2015 and decreased in both Canada and the US. In Canada production was down as uneconomic wells have been shut-in and in the US production was down as new wells in North Dakota experienced their normal decline during the quarter and wells recently drilled have not yet commenced production.

Net Debt

The Company's credit facility was reviewed in May 2015 based on the Company's yearend engineering report prepared by an independent petroleum engineer. Based on the reserves as determined in the engineering report and applying the price deck as provided by the syndicate, the new borrowing base was revised to $55.0 million. The credit facility included a $45.0 million Extendable Syndicated Credit Facility, a $10.0 million Extendable Operating Credit Facility and a $15.0 million Supplemental Credit Facility (together the "Facility"). The Supplemental Credit Facility, that was available by way of a single advance on the effective date, was drawn at $12.0 million, is required to be repaid by May 31, 2016 and 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. A semi-annual review of the borrowing base is to be completed on or before November 30, 2015.

Net debt at June 30, 2015 was $56.6 million, down from $65.2 million at December 31, 2014. Net debt has decreased from December 31, 2014 due primarily to the monetizing of the Company's commodity risk management contracts that generated proceeds of $13.2 million.

Net Debt Reconciliation

(000's Cdn. $)	**Six Months Ended June 30**
Net debt December 31, 2014	**65,198**
Funds from operations	**(21,919)**
Additions to property, plant and equipment	**12,706**
Exploration and evaluation expenses	**2,543**
Dividends	**775**
Cash portion of share incentive awards settled	**125**
Decommissioning liabilities settled	**171**
Proceeds on sale of properties	**(1,677)**
Foreign exchange gain on US cash held	**(135)**
Change in working capital and other items	**(1,152)**
Net debt June 30, 2015	**56,635**

Private Placement

On July 14, 2015, the Company closed a private placement for gross proceeds of $4.6 million issuing 778,460 common shares at $3.15 per common share and 585,700 flow-through common shares at $3.70 per flow-through common share. The proceeds from the common shares will be used to reduce amounts outstanding under the Company's Supplemental Credit Facility while the proceeds from the flow-through shares will be used to incur Canadian Exploration Expenses that will be renounced to the investors of flow-through shares effective December 31, 2015. The expenditures are required to be incurred by December 31, 2016.

Net Loss

The Company recorded a net loss in Q2 2015 of $3.4 million or $0.19 per share basic and diluted versus a loss of $375,824 or $0.02 per share basic and diluted in Q2 2014. Production decreased 10% from Q2 2014. Low commodity prices during the quarter resulted in a 43% lower operating netback when compared to Q2 2014. In addition, a loss on the sale of properties of $1.4 million also contributed to the current quarter loss. For the six months ended June 30, 2015, the Company recorded a loss of $3.9 million or $0.22 per share basic and diluted versus income of $652,361 or $0.04 per share basic and diluted in the 2014 six month period. The operating margin in the six months ended June 30, 2015 was down 56% from the six months ended June 30, 2014 while production was down 6% in the six months ended June 30, 2015 versus the six months ended June 30, 2014. The lower operating margin offset a reduction in the risk management contract loss, recoveries of previously expensed share based compensation and a gain on foreign exchange.

Capital Expenditures

Capital expenditures for Q2 2015 to property, plant and equipment totaled $6.0 million down from $17.2 million in Q2 2014. Expenditures in Q2 2015 were incurred in Canada ($1.4 million) primarily on well equipment and facilities at Princess. Expenditures in Q2 2015 were incurred in the US, ($4.6 million) primarily to complete and equip Bakken and Three Forks wells at Lindahl.

Corporate Information

As of August 4, 2015, Arsenal has 19,332,706 common shares, 663,837 stock options and 394,911 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 2,481 Boe per day for Q2 2015. In the US, the Company operates under its 100% indirectly owned subsidiary Arsenal Energy U.S.A. Inc. and had average production of 1,365 Boe per day for Q2 2015.

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 and six months ended June 30, 2015. It should be read in conjunction with the audited consolidated financial statements and related notes of the Company for the year ended December 31, 2014. 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 August 4, 2015.

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 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.

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 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 and income taxes) to measure debt 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 netback is funds from operations calculated on a Boe basis.

Operating income is calculated as revenue generated from oil and natural gas 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 excludes long term decommissioning obligations and risk management contracts (whether an asset or an obligation and whether classified as short or long term).

Net Cash from Operating Activities and Funds from Operations

The following table compares net cash from operating activities to funds from operations for Q2 2015 to Q2 2014 and for the six months ended June 30, 2015 to the six months ended June 30, 2014:

(000's Cdn. $)	Three Months Ended June 30 **2015**	2014	% Change	Six Months Ended June 30 **2015**	2014	% Change
Net cash from operating activities	**2,405**	6,619	(64)	**19,514**	14,248	37
Exploration and evaluation expenses	**877**	1,276	(31)	**2,543**	1,920	32
Decommissioning obligations settled	**84**	367	(77)	**171**	601	(72)
Change in non-cash working capital	**2,793**	3,348	(17)	**(309)**	5,894	(105)
Funds from operations	**6,159**	11,610	(47)	**21,919**	22,663	(3)

Net cash from operating activities generated in Q2 2015 totaled $2.4 million versus $6.6 million generated in Q2 2014 and for the six months ended June 30, 2015 totaled $19.5 million versus $14.2 million in the 2014 six month period. Net cash from operating activities differs from the Company's calculation of funds from operations due primarily to the Company's policy of expensing exploration and evaluation expenditures, transaction costs the timing of incurring decommissioning expenditures and to the changes in non-cash working capital items.

For Q2 2015, funds from operations totaled $6.1 million or $17.60 per Boe versus $11.6 million or $29.72 per Boe for Q2 2014. The operating netback for Q2 2015 was $23.19 per Boe versus $40.69 per Boe in Q2 2014. The average price received decreased by $32.53 per Boe. For the six months ended June 30, 2015, funds from operations dropped by $743,632 when compared to the 2014 six month period. Lower commodity prices, down by 45%, reduced the six month 2015 operating margin by $17.9 million from 2014. This was offset by a realized gain on commodity risk management contracts of $13.2 million.

The following table compares funds from operations by country and funds from operations per Boe for Q2 2015 to Q2 2014 and for the respective six month comparative periods in 2015 and 2014. These numbers are referred to throughout the MD&A:

Funds From Operations By Country

(000's Cdn. $)	Three Months Ended June 30 **2015**	2014	% Change	Six Months Ended June 30 **2015**	2014	% Change
Canada	**3,816**	6,665	(43)	**17,523**	12,802	37
US	**2,343**	4,944	(53)	**4,396**	9,861	(55)
Funds from operations	**6,159**	11,610	(47)	**21,919**	22,663	(3)

Funds From Operations Per Boe

($Cdn.)	Three Months Ended June 30 **2015**	2014	% Change	Six Months Ended June 30 **2015**	2014	% Change
Canada	**16.90**	26.49	(36)	**38.31**	**25.69**	49
US	**18.87**	35.58	(47)	**16.98**	**37.64**	(55)
Total	**17.60**	29.72	(41)	**30.60**	29.81	3

The following tables provide a comparison of the previous eight quarters of 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.

Production

	2015			2014			2013	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Oil and NGL (bbls/d)	**2,925**	3,129	3,701	3,857	3,386	2,979	3,046	3,236
Natural gas (mcf/d)	**5,528**	5,648	6,247	5,943	5,435	6,776	6,012	6,523
Total Boe	**349,956**	366,349	436,245	445,996	390,583	369,746	372,410	397,702
Boe per day	**3,846**	4,071	4,742	4,848	4,292	4,108	4,048	4,323

Production by Country

	2015			2014			2013	
(Boe per day)	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Canada	**2,481**	2,574	2,990	2,950	2,765	2,741	2,332	2,461
US	**1,365**	1,497	1,752	1,898	1,527	1,367	1,716	1,862
Total	**3,846**	4,071	4,742	4,848	4,292	4,108	4,048	4,323

Funds from Operations by Country

	2015			2014			2013	
(000's Cdn. $)	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Canada	**3,816**	13,707	10,758	8,029	6,665	6,137	2,871	2,294
US	**2,343**	2,053	6,148	6,965	4,945	4,916	6,142	9,401
Total	**6,159**	15,760	16,906	14,994	11,610	11,053	9,013	11,695

Funds from Operations by Country per Boe

	2015			2014			2013	
(Cdn. $)	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Canada	**16.90**	59.16	39.11	29.58	26.49	24.87	13.39	10.13
US	**18.87**	15.25	38.14	39.89	35.58	39.96	38.90	54.88
Total	**17.60**	43.02	38.75	33.62	29.72	29.89	24.20	29.41

Funds from Operations

	2015			2014			2013	
(000's Cdn. $)	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Before risk management contracts	**6,221**	2,632	10,528	16,351	13,860	12,597	10,002	13,725
Realized risk management contracts	**(62)**	13,128	6,378	(1,357)	(2,250)	(1,544)	(989)	(2,030)
After commodity contracts	**6,159**	15,760	16,906	14,994	11,610	11,053	9,013	11,695

Funds from Operations Netback Per Boe

	2015			2014			2013	
(Cdn. $)	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Before risk management contracts	**17.78**	7.18	24.13	36.66	35.49	34.07	26.89	34.51
After risk management contracts	**17.60**	43.02	38.75	33.62	29.72	29.89	24.20	29.41

The increases and decreases in the above periods for funds from operations relate primarily to successful drilling, 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, 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 North Dakota Bakken production 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.

OUTLOOK AND 2015 GUIDANCE

With WTI currently trading below $50.00 US per barrel range and with differentials increasing, the ability to find and produce oil at a profit is uncertain even with reduced drilling and operating costs and a weaker Canadian dollar. Crude prices need to improve over the long run to ensure a profitable oil industry. Fortunately the strip pricing for crude reflects some improvement in prices over time and with further cost savings and reductions and with the application of new technology, the industry will revitalize itself and become vibrant once again.

The Company has a flow-through share commitment to fulfill and has planned an exploratory drilling program during the last half of 2015 to fulfill this commitment. Arsenal is proceeding cautiously and carefully with this program focusing on the Princess and Provost areas in Alberta, areas where the well evaluation costs are relatively cheap but that, if successful, will deliver good margins, rates of return, reserve additions and that will provide the Company with a future growth platform. US operated drilling will be deferred until prices improve but the Company will participate in wells being proposed by partners in order to preserve the Company's working interests and reserves in the area.

Guidance

Arsenal's capital expenditures are now forecasted at approximately $27.0 million for 2015, of which approximately $10.0 million will be spent in the US and approximately $17.0 million will be spent in Canada. In the US, expenditures are being spent to complete production facilities at Lindahl, North Dakota. In Canada, expenditures are expected to be incurred, all in Alberta, to drill and complete three gross (3 net) wells at Princess, two gross (2 net) wells at Provost and one gross (1 net) well at Cessford, on land, on capitalized general and administrative expenditures and on miscellaneous other initiatives.

Arsenal issued initial 2015 guidance in January 2015 and due to further weakening of crude prices revised its guidance in February 2015. Current guidance differs only slightly from the guidance issued in February 2015. Production in 2015 is expected to be reduced slightly to 4,000 boe/d due to the delayed timing of bringing wells on production in Lindahl, North Dakota. Capital expenditures have been increased slightly to approximately $27.0 million while funds from operations are expected to total approximately $33.5 million up slightly from $33.0 million. Cash flow is based on the current strip pricing (WTI to average approximately $51.05 US per barrel). Due to an equity issue that closed in July 2015, 2015 year end debt is expected to be approximately $54.0 million. Exit production is expected to be approximately 4,400 boe/d.

Production

Production for Q2 2015 averaged 3,846 Boe per day, a 6% decrease from 4,071 Boe per day in Q1 2015 and a 10% decrease from 4,292 Boe per day in Q2 2014. Average production was down from Q1 2015 in Canada primarily due to shutting in of uneconomic oil wells in the Provost, Consort and Galahad areas and in the US from normal production declines at Stanley. The decline from Q2 2014 was due to the shutting in of uneconomic wells and due to lower production at Princess, Alberta and Stanley, North Dakota due to normal reservoir declines. Higher production from a Q4 2014 light oil well drilled at Evi and higher production at Lindahl, North Dakota from Q1 2015 drilling partially offset these declines.

For the six months ended June 30, 2015, production averaged 3,957 Boe per day versus 4,201 Boe per day in the six months ended June 30, 2014. Lower production resulted from uneconomic wells being shut-in and normal production declines offset by increased production at Evi, Alberta and Lindahl, North Dakota.

Production Profile

By Country

	Three Months Ended June 30			Six Months Ended June 30		
	2015	2014	% Change	**2015**	2014	% Change
Canada	**65%**	64%	1	**64%**	66%	(3)
US	**35%**	36%	(1)	**36%**	34%	5

The percentage of production in Canada versus in the US can change as a result of second half 2015 drilling at Princess and Provost in Alberta and from the timing of wells waiting to be brought on production at Lindahl. Production from new US drilling tends to offset production declines resulting in relatively level US production period over comparative period. In this current lower priced commodity environment, the Company expects to focus more of its capital expenditure budget in Canada at Princess and Provost, Alberta due to the ability to attain better margins.

Production by Area

	Three Months Ended June 30					Six Months Ended June 30				
	2015		2014			**2015**		2014		
AREA	**Boe/d**	**% of Total**	Boe/d	% of Total	**% Change**	**Boe/d**	**% of Total**	Boe/d	% of Total	**% Change**
Canada										
Galahad (light oil)	**81**	**2**	109	2	**(26)**	**87**	**2**	103	3	**(16)**
Princess (medium oil and gas)	**916**	**24**	1,041	24	**(12)**	**919**	**24**	1,046	25	**(12)**
Chauvin (medium oil and gas)	**262**	**7**	263	6	**-**	**260**	**7**	262	6	**-**
Provost (medium oil and gas)	**256**	**7**	419	10	**(39)**	**283**	**7**	421	10	**(33)**
Consort (medium oil and gas)	**64**	**2**	79	2	**(19)**	**62**	**1**	75	2	**(17)**
Evi (light oil)	**225**	**6**	112	3	**101**	**218**	**6**	125	3	**74**
Desan (gas)	**560**	**14**	598	14	**(6)**	**564**	**14**	583	14	**(3)**
Others	**117**	**3**	144	3	**(19)**	**134**	**3**	138	3	**(3)**
Total Canada	**2,481**	**65**	2,765	64	**(10)**	**2,527**	**64**	2,753	66	**(8)**
US										
Stanley (light oil)	**999**	**26**	1,235	29	**(19)**	**1,077**	**28**	1,166	27	**(8)**
Lindahl (light oil)	**299**	**8**	209	5	**43**	**290**	**7**	206	5	**41**
Rennie Lake/Black Slough (light oil)	**55**	**1**	65	2	**(15)**	**51**	**1**	57	1	**(11)**
Lake Darling (light oil)	**12**	**-**	18	-	**(33)**	**12**	**-**	19	1	**(37)**
Total US	**1,365**	**35**	1,527	36	**(11)**	**1,430**	**36**	1,448	34	**(1)**
Total	**3,846**	**100**	4,292	100	**(10)**	**3,958**	**100**	4,201	100	**(6)**

Revenue

Prices - Before Commodity Contracts

	Three Months Ended June 30			**Six Months Ended June 30**		
($Cdn.)	**2015**	2014	% Change	**2015**	2014	% Change
Canada						
Heavy oil per barrel	**45.32**	87.94	(48)	**43.17**	78.85	(45)
Medium oil and NGL's per barrel	**57.37**	89.93	(36)	**49.16**	88.17	(44)
Natural gas per mcf	**2.12**	4.46	(52)	**2.17**	4.96	(56)
Total per Boe	**42.40**	71.25	(40)	**37.20**	68.14	(45)
US						
Heavy oil per barrel	**-**	-	-	**-**	-	-
Light oil and NGL's per barrel	**56.74**	96.56	(41)	**52.88**	96.58	(45)
Natural gas per mcf	**3.36**	6.96	(52)	**3.89**	7.34	(47)
Total per Boe	**54.22**	93.36	(42)	**50.82**	93.70	(46)
Total						
Heavy oil per barrel	**45.32**	87.94	(48)	**43.17**	78.85	(45)
Oil and NGL's per barrel	**57.09**	92.78	(38)	**50.81**	91.83	(45)
Natural gas per mcf	**2.25**	4.71	(52)	**2.35**	5.15	(54)
Total per Boe	**46.59**	79.12	(41)	**42.12**	76.95	(45)

Reference Prices

	Three Months Ended June 30			Six Months Ended June 30		
	2015	2014	% Change	**2015**	2014	% Change
WTI Cushing, Oklahoma ($U.S./bbl)	**57.94**	102.99	(44)	**53.29**	100.82	(47)
Canadian Light Sweet ($Cdn./bbl)	**68.88**	104.14	(34)	**61.08**	101.95	(40)
Hardisty Heavy 12 API ($Cdn./bbl)	**56.49**	84.79	(33)	**47.64**	81.55	(42)
Hardisty Bow River 24.9 API ($Cdn./bbl)	**57.49**	90.69	(37)	**50.30**	87.35	(42)
AECO (30 day spot) ($Cdn./MMBtu)	**2.67**	4.70	(43)	**2.71**	5.16	(47)
Henry Hub NYMEX Close ($U.S./MMBtu)	**2.74**	4.58	(40)	**2.77**	4.66	(41)
Foreign exchange ($Cdn./$U.S.)	**1.23**	1.09	13	**1.24**	1.10	13

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 $57.37 per Boe for its medium oil and NGL in the current of quarter, a decreased of 36% versus Q2 2014. 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 37% in Q2 2015 over Q2 2014. The price received for natural gas decreased 52% in Canada and in the US in Q2 2015 versus Q2 2014. The price received for natural gas in Canada generally tracks changes to the AECO price which was down 43% from Q2 2014 and in the US, the Henry Hub price was down 40% from Q2 2014.

In the US, the price received for light oil decreased 41%. This corresponds to a 44% decrease in the price of WTI in the current quarter over the comparative quarter in 2014.

The Company received an average price per Boe during Q2 2015 of $46.59 per Boe, a decrease of 41% from $79.12 per Boe received in Q2 2014. This decrease is attributed to the 44% decline, during the quarter, in the price of WTI and a decrease in Q2 2015 from Q2 2014 in the price of natural gas in both Canada (AECO) and the US (Henry Hub) of 43% and 40% respectively.

For the 2015 six month period, the Company received an average price of $42.12 per Boe versus $76.95 per Boe received in the six months ended June 30, 2014. This decrease generally corresponds to the decrease in the price of WTI of 47% over the six month period. In addition, natural gas prices declined in both Canada (AECO) and the US (Henry Hub) by 56 and 47% respectively.

Revenues

	Three Months Ended June 30			Six Months Ended June 30		
(000's Cdn. $)	**2015**	2014	% Change	**2015**	2014	% Change
Canada						
Heavy oil	**73**	289	(75)	**223**	588	(62)
Medium oil and NGL's	**8,540**	15,648	(45)	**14,831**	28,315	(48)
Natural gas	**958**	1,990	(52)	**1,961**	5,055	(61)
Total	**9,572**	17,927	(47)	**17,015**	33,958	(50)
US						
Light oil and NGL's	**6,561**	12,636	(48)	**12,736**	23,919	(47)
Natural gas	**172**	339	(49)	**420**	632	(33)
Total	**6,733**	12,975	(48)	**13,156**	24,551	(46)
Total						
Heavy oil	**73**	289	(75)	**223**	588	(62)
Oil and NGL's	**15,101**	28,284	(47)	**27,567**	52,234	(47)
Natural gas	**1,131**	2,329	(51)	**2,381**	5,687	(58)
Oil and natural gas revenues	**16,305**	30,902	(47)	**30,171**	58,508	(48)
Gain (loss) on realized crude commodity contracts	**-**	(2,237)	-	**13,154**	(3,764)	449
Oil and gas revenue after realized crude commodity contracts	**16,305**	28,665	(43)	**43,325**	54,744	(21)
Revenue per boe before realized crude commodity contracts	**46.59**	79.12	(41)	**42.12**	76.95	(45)
Revenue per boe after realized crude commodity contracts	**46.59**	73.39	(37)	**60.48**	72.00	(16)

Oil and natural gas revenues totaled $16.3 million for Q2 2015 a decrease of 47% over Q2 2014 due to a 41% decrease in the average price received per Boe and a 10% decrease in production. For the six months ending June 30, 2015, revenues decreased 48% to $30.2 million versus $58.5 million in the 2014 six month period due to a 45% decrease in the average price received and a 6% decrease in production.

Revenues in the current quarter and six month 2015 period in Canada decreased 47% and 50% respectively and in the US decreased 48% and 46% respectively. Average price received per Boe in Q2 2015 decreased $28.85 per boe in Canada and $39.14 per Boe in the US from Q2 2014. Average price received per Boe in the six month 2015 period decreased $30.94 per boe in Canada and $42.88 per Boe in the US from the 2014 six month period.

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.

During the quarter ended June 30, 2015, the Company recorded a net loss of $271,914 on its financial instrument (commodity price and interest rate) contracts, of which $62,414 was realized in Q2 2015 on the interest rate swap. For the six months ended June 30, 2015, the Company recorded a net gain of $660,417 on its financial instrument (commodity price and interest rate) contracts, of which $13.1 million was realized primarily on the monetization of its December 31, 2014 crude commodity contracts.

In 2015, subsequent to monetizing the Company's crude commodity contracts, the Company has entered into swap contracts for crude as follows:

($Cdn. unless otherwise noted)				
Commodity Sold	Volume Sold	Remaining Term	Pricing	Fair Value
Oil	300 bbl per day	July 1, 2015 - September 30, 2015	$63.00 US per bbl	107
Oil	500 bbl per day	October 1, 2015 - December 31, 2015	$60.80 US per bbl	(3)
Oil	300 bbl per day	January 1, 2016 - March 31, 2016	$57.90 US per bbl	(122)
Oil	300 bbl per day	April 1, 2016 - June 30, 2016	$78.20 Cdn. per bbl	18
				-

At June 30, 2015, the Company has recorded a current risk management asset relating to its crude contracts totaling $121,591 and a total liability of $776,714 of which $375,570 is classified as a current liability. The position has been calculated based on a June 30, 2015 WTI Canadian dollar strip price for Q3 2015 of approximately $72.38 Canadian ($57.47 US) per barrel, for Q4 2015 of approximately $73.96 Canadian ($58.65 US) per barrel, for Q1 2016 of approximately $75.12 Canadian ($59.53 US per barrel) for Q2 2016 of approximately $75.97 Canadian ($60.20 US) per barrel.

Any future asset or liability recorded changes with changes to the price of West Texas Intermediate and with changes to the Canadian/US dollar exchange rate.

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	Fair Value
30 day BA rate	July 1, 2015 - February 13, 2018	$ 30,000,000	CAD - BA - CDOR	1.80%	Swap	(655)

The rates above are, as provided for in 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 two most recent quarter ends annualized.

As at June 30, 2015, the Company has an interest rate risk management liability recorded totaling $654,498.

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

Gains (Losses) on Risk Management Contracts

	Three Months Ended June 30			Six Months Ended June 30		
(000's Cdn. $)	**2015**	2014	% Change	**2015**	2014	% Change
Realized gain (loss)						
Commodity	**-**	(2,236)	-	**13,154**	(3,764)	449
Interest rate	**(62)**	(14)	(343)	**(88)**	(30)	(193)
Total	**(62)**	(2,250)	97	**13,066**	(3,794)	(444)
Unrealized gain (loss)						
Commodity	**(300)**	37	(911)	**(11,946)**	(1,415)	(744)
Interest rate	**91**	13	600	**(459)**	24	(2,013)
Total	**(209)**	50	518	**(12,405)**	(1,391)	792
Total gain (loss)						
Commodity	**(300)**	(2,199)	(86)	**1,208**	(5,179)	123
Interest rate	**29**	(1)	3,000	**(547)**	(6)	(9,017)
Total risk management contracts	**(271)**	(2,200)	88	**661**	(5,185)	113
Per Boe realized risk management contracts	**(0.18)**	(5.76)	97	**18.24**	(4.99)	466
Per Boe unrealized risk management contracts	**(0.60)**	0.13	567	**(17.32)**	(1.83)	(847)
	(0.78)	(5.63)	86	**0.92**	(6.82)	114

Royalties

	Three Months Ended June 30			Six Months Ended June 30		
(000's Cdn. $)	**2015**	2014	% Change	**2015**	2014	% Change
Canada						
Heavy oil	**7**	49	(86)	**20**	73	(72)
Medium oil and NGL's	**1,183**	2,899	(59)	**2,958**	4,767	(38)
Natural gas	**12**	229	(95)	**24**	551	(96)
Total	**1,203**	3,178	(62)	**3,002**	5,391	(44)
US						
Light oil and NGL's	**1,878**	3,599	(48)	**3,600**	6,746	(47)
Natural gas	**36**	73	(51)	**83**	135	(39)
Total	**1,913**	3,672	(48)	**3,683**	6,881	(46)
Total						
Heavy oil	**7**	49	(86)	**20**	73	(72)
Oil and NGL's	**3,061**	6,498	(53)	**6,558**	11,513	(43)
Natural gas	**48**	303	(84)	**106**	686	(84)
Royalties	**3,116**	6,851	(55)	**6,685**	12,272	(46)
Royalties per Boe	**8.90**	17.54	(49)	9.33	16.14	(42)

Percentage By Product

	Three Months Ended June 30			Six Months Ended June 30		
	2015	2014	% Change	**2015**	2014	% Change
Heavy oil	**10**	17	(43)	**9**	12	(26)
Oil and NGL's	**20**	23	(12)	**24**	22	8
Natural gas	**4**	13	(67)	**4**	12	(63)
Total	**19**	22	(14)	**22**	21	6

Percentage By Country

	Three Months Ended June 30			Six Months Ended June 30		
	2015	2014	% Change	**2015**	2014	% Change
Canada	**13**	18	(29)	**18**	16	11
US	**28**	28	-	**28**	28	-
Total	**19**	22	(14)	**22**	21	6

The Company’s overall royalty rate for Q2 2015 averaged 19% compared to 22% for Q2 2014. For the six month ended June 30, 2015, the royalty rate averaged 22% versus 21% for the six months ended June 30, 2014. Lower prices and lower well production has contributed to reduce royalty rates in the current quarter while lower prices and lower production in the six month period were offset by an assessment of additional freehold royalties related to a prior period thereby slightly increasing the current six month royalty rate.

During the current quarter and during the six month June 30, 2015 period, the royalty rate for natural gas has decreased as royalty rates are somewhat price sensitive (down 52%) in Q2 2015.

Going forward, the corporate royalty rate is expected to average in the 20% - 22% range. In Canada, the rate fluctuates due to the timing of drilling low royalty rate wells, to production increases from higher royalty rate US wells and to some extent, commodity prices and production rates. Increases or decreases in the dollar value of royalties are somewhat 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 land owners and a production royalty 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 prices.

Operating and Transportation Expenses

	Three Months Ended June 30			Six Months Ended June 30		
(000's Cdn. $)	**2015**	2014	**% Change**	**2015**	2014	% Change
Canada						
Heavy oil	**54**	103	(47)	**215**	293	(27)
Medium oil and NGL's	**3,199**	5,415	(41)	**6,728**	10,865	(38)
Natural gas	**951**	1,287	(26)	**2,087**	2,497	(16)
Total	**4,203**	6,805	(38)	**9,030**	13,654	(34)
US						
Light oil and NGL's	**850**	1,342	(37)	**1,986**	2,346	(15)
Natural gas	**21**	13	67	**56**	33	71
Total	**872**	1,355	(36)	**2,042**	2,379	(14)
Total						
Heavy oil	**54**	103	(47)	**215**	293	(27)
Oil and NGL's	**4,049**	6,757	(40)	**8,715**	13,211	(34)
Natural gas	**972**	1,300	(25)	**2,143**	2,529	(15)
Operating and transportation	**5,075**	8,159	(38)	**11,072**	16,033	(31)
Operating and transportation per Boe	**14.50**	20.89	(31)	**15.46**	21.09	(27)

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 Q2 2015 by $3.1 million or 38% from Q2 2014 and by $5.0 million or 31% for the six months ended June 30, 2015 versus the comparative 2014 six month period. On a Boe basis, operating costs decreased in Q2 2015 to $14.50 per boe from $20.89 per boe in Q2 2014 and for the six months ended June 30, 2015 to $15.46 per Boe versus $21.09 per Boe for the six months ended June 30, 2014. The reduction in operating costs is due to a 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

($Cdn.)	Three Months Ended June 30 2015 Canada	US	Corporate	Three Months Ended June 30 2014 Canada	US	Corporate	Corporate % Change
Heavy oil							
Revenue	**45.32**	**-**	**45.32**	87.94	-	87.94	**(48)**
Royalty	**(4.39)**	**-**	**(4.39)**	(15.02)	-	(15.02)	**(71)**
Operating and transportation	**(33.43)**	**-**	**(33.43)**	(31.28)	-	(31.28)	**7**
Operating netback per barrel	**7.50**	**-**	**7.50**	41.65	-	41.65	**(82)**
Medium and light oil and NGL's							
Revenue	**57.37**	**56.74**	**57.09**	89.93	96.56	92.78	**(38)**
Royalty	**(7.95)**	**(16.24)**	**(11.57)**	(16.66)	(27.50)	(21.32)	**(46)**
Operating and transportation	**(21.49)**	**(7.35)**	**(15.31)**	(31.12)	(10.25)	(22.16)	**(31)**
Operating netback per barrel	**27.93**	**33.15**	**30.21**	42.15	58.80	49.30	**(39)**
Natural gas							
Revenue	**2.12**	**3.36**	**2.25**	4.46	6.96	4.71	**(52)**
Royalty	**(0.03)**	**(0.69)**	**(0.10)**	(0.51)	(1.51)	(0.61)	**(84)**
Operating and transportation	**(2.10)**	**(0.42)**	**(1.93)**	(2.89)	(0.26)	(2.63)	**(26)**
Operating netback per mcf	**(0.01)**	**2.24**	**0.22**	1.06	5.19	1.47	**(85)**
Boe							
Revenue	**42.40**	**54.22**	**46.59**	71.25	93.36	79.12	**(41)**
Royalty	**(5.33)**	**(15.41)**	**(8.90)**	(12.63)	(26.42)	(17.54)	**(49)**
Operating and transportation	**(18.62)**	**(7.02)**	**(14.50)**	(27.05)	(9.75)	(20.89)	**(31)**
Operating netback per Boe	**18.45**	**31.79**	**23.19**	31.58	57.18	40.69	**(43)**

($Cdn.)	Six Months Ended June 30 2015 Canada	US	Corporate	Six Months Ended June 30 2014 Canada	US	Corporate	Corporate % Change
Heavy oil							
Revenue	**43.17**	**-**	**43.17**	78.85	-	78.85	**(45)**
Royalty	**(3.95)**	**-**	**(3.95)**	(9.76)	-	(9.76)	**(60)**
Operating and transportation	**(41.52)**	**-**	**(41.52)**	(39.26)	-	(39.26)	**6**
Operating netback per barrel	**(2.30)**	**-**	**(2.30)**	29.83	-	29.83	**(108)**
Medium and light oil and NGL's							
Revenue	**49.16**	**52.88**	**50.81**	88.17	96.58	91.83	**(45)**
Royalty	**(9.80)**	**(14.95)**	**(12.09)**	(14.84)	(27.24)	(20.24)	**(40)**
Operating and transportation	**(22.30)**	**(8.25)**	**(16.06)**	(33.83)	(9.47)	(23.23)	**(31)**
Operating netback per barrel	**17.05**	**29.68**	**22.66**	39.49	59.87	48.36	**(53)**
Natural gas							
Revenue	**2.17**	**3.89**	**2.35**	4.96	7.34	5.15	**(54)**
Royalty	**(0.03)**	**(0.77)**	**(0.11)**	(0.54)	(1.57)	(0.62)	**(83)**
Operating and transportation	**(2.31)**	**(0.52)**	**(2.12)**	(2.45)	(0.38)	(2.29)	**(7)**
Operating netback per mcf	**(0.17)**	**2.61**	**0.13**	1.97	5.40	2.24	**(94)**
Boe							
Revenue	**37.20**	**50.82**	**42.12**	68.14	93.70	76.95	**(45)**
Royalty	**(6.56)**	**(14.23)**	**(9.33)**	(10.82)	(26.26)	(16.14)	**(42)**
Operating and transportation	**(19.74)**	**(7.89)**	**(15.46)**	(27.40)	(9.08)	(21.09)	**(27)**
Operating netback per Boe	**10.89**	**28.71**	**17.33**	29.93	58.36	39.72	**(56)**

Canadian Netback

The Q2 2015 operating netback from Canadian medium oil and NGL decreased $14.22 per barrel or 34% from Q2 2014. The six month netback for 2015 declined by $22.44 per barrel or 57% to $17.05 per barrel from $39.49 per barrel for the 2014 six month period. Lower average crude prices in 2015 were offset by lower operating expenses. The average price received decreased by 36% in the quarter and 44% during the six months ended June 30, 2015. Meanwhile operating expenses decreased 31% in the current quarter and 34% in the current six month period from the prior year comparative period.

The Q2 2015 operating netback from Canadian heavy oil production increased $14.25 per barrel from Q1 2015 due primarily to lower operating costs. For the six months ended June 30, 2015, the operating netback declined $32.13 per barrel or 108% to a loss of $2.30 per barrel. Looking forward, lower operating costs should improve the operating netback.

The Q2 2015 netback from Canadian natural gas decreased $1.07 per mcf or 101% from Q2 2014 due to lower prices that declined by 52% when compared to Q2 2014.

US Netback

The Q2 2015 netback from the US light oil and NGL decreased $25.65 per barrel or 44% from Q2 2014 and by $30.18 or 50% from the comparative six month period in 2014. Lower crude prices were responsible for this decline.

The Q2 2015 netback from the US natural gas decreased $2.95 per mcf or 57% from Q2 2014 and by $2.79 or 52% in the six month period. These declines are due to lower prices that declined by 52% in the current quarter and by 47% in the current six month period from prior year comparative periods.

Corporate Netback

Arsenal's Q2 2015 average price decreased $32.53 per Boe or 41% to $46.59 per Boe from $79.12 per Boe received in Q2 2014 resulting in a reduced netback of $23.19 per Boe. For the six months ended June 30, 2015, the corporate netback decreased 56% to 17.33 per Boe due to a lower average price that declined by 45%.

General and Administrative Expenses

	Three Months Ended June 30			Six Months Ended June 30		
(000's Cdn. $)	**2015**	2014	% Change	**2015**	2014	% Change
Gross expenditures	**1,877**	1,937	(3)	**3,639**	3,586	1
Overhead recovery	**(579)**	(563)	3	**(1,065)**	(1,062)	-
Capitalized overhead	**(150)**	(225)	(33)	**(325)**	(387)	(16)
Net general and administrative expense	**1,148**	1,149	-	**2,249**	2,136	5
Net general and administrative per boe	**3.28**	2.94	12	**3.14**	2.81	12

Gross general and administrative expenditures were lower in Q2 2015 by $59,556 and higher in the 2015 six month period by $53,164 when compared to their respective 2014 periods. On a net basis, general and administrative expenses decreased in Q2 2015 over Q2 2014 by $873 and increased by $112,629 in the 2015 six month period versus the 2014 six month period. With the reduction in the Company's funds from operations that has materialized from lower commodity prices and production, the Company has initiated certain cost reductions including a reducing the staff level, a movement to part time employees and consultants and a reduced bonus provision. These initiatives, while some increase costs in the short term, should result in lower gross and net costs going forward. In addition, due to the decision to defer drilling until the later part of 2015, the Company reduced the dollar value of overhead capitalized in both the quarter and the six month period.

On a Boe basis, general and administrative expenditures for the current quarter increased to $3.28 per Boe from $2.94 per Boe in Q2 2014 and for the current six month period to $3.14 per Boe from $2.81 per Boe in the 2014 six month period. The increases of 12% in the respective periods are the result of lower production – down 10% and 6% in the respective periods and reduced overhead capitalized.

Exploration and Evaluation Expenses

	Three Months Ended June 30			Six Months Ended June 30		
(000's Cdn. $)	**2015**	2014	% Change	**2015**	2014	% Change
Exploration and evaluation expenses	**877**	1,276	(31)	**2,543**	1,920	32
Per Boe	**2.50**	3.27	(23)	**3.55**	2.52	41

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 2015, the Company incurred certain seismic expenditures in Cessford, Provost and Princess, Alberta related to its prospect exploration and development program. In 2014, the seismic expenditures were incurred primarily in Princess, Alberta.

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 the greater of its fair value in use or its fair value less costs to sell.

An impairment loss is recognized if the carrying amount of an asset or its Cash Generating Unit ("CGU") exceeds its value in use or fair value less costs to sell. 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 June 30, 2015 and June 30, 2014, no impairments existed.

The fair value amount of the Company's CGU's are sensitive to 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 June 30			Six Months Ended June 30		
(000's Cdn. $)	**2015**	2014	% Change	**2015**	2014	% Change
Interest and other financing charges	**523**	703	(26)	**1,059**	1,366	(22)
Per Boe	**1.49**	1.80	(17)	**1.48**	1.80	(18)

Interest and other financing charges 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 25% in Q2 2015 from Q2 2014 and 22% for the current six month period from the 2014 six month period due primarily to lower interest paid on the Company's borrowings. For Q2 2015, the average daily borrowing balance was $56.1 million versus $72.1 million for Q2 2014. For the six months ended June 30, 2015, interest and other financing charges were down by 22% due to a lower average daily borrowing balance ($54.3 million to June 30, 2015 versus $71.7 million to June 30, 2014).

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 $12.0 million on the Supplemental Credit Facility commenced on May 28, 2015.

Depletion and Depreciation

	Three Months Ended June 30			Six Months Ended June 30		
(000's Cdn. $)	**2015**	2014	% Change	**2015**	2014	% Change
Depletion and depreciation	**6,866**	7,407	(7)	**14,308**	14,169	1
Per boe	**19.62**	18.97	3	**19.98**	18.64	7

On an absolute dollar basis, depletion and depreciation in Q2 2015 decreased 7% from Q2 2014. This decrease was attributed primarily to a 10% decrease in average production offset by a higher cost base and a lower reserve depletion base. On a Boe basis, depletion and depreciation increased 3% to $19.62 per Boe in Q2 2015 versus $18.97 per Boe in Q2 2014. The increase is due to a stronger US dollar thereby increasing historical and future development costs in Canadian dollar terms and to a year-end reduction in US reserves.

In Canada, the depletion and depreciation rate decreased from $17.40 per Boe in Q2 2014 to $15.53 per Boe in Q2 2015 based on increased reserves at Princess, Alberta and on positive performance adjustments in some other areas. The decrease was partially offset by an increase in the cost estimate to abandon and decommission wells and to a decrease in the discount rate applied to the decommissioning liabilities in Canada.

In the US, the depreciation and depletion rate increased from $21.79 per Boe in Q2 2014 to $27.07 per Boe in Q2 2015 due, to a year-end reduction in reserves, to a stronger US dollar (up 13% from December 31, 2014), to an increase in the cost estimate to abandon and decommission wells and to a decrease in the discount rate applied to the decommissioning liabilities in the US.

On an absolute dollar basis, depletion and depreciation for the first six month of 2015 increased 1% from the 2014 six month period. On a Boe basis, depletion and depreciation increased 7% to $19.98 per Boe versus $18.64 per Boe. In Canada the rate decreased to $15.88 per Boe from $17.32 per Boe and in the US, the rate increased to $27.21 per Boe from $21.14 per Boe. The increase is due to a stronger US dollar thereby increasing historical and future development costs in Canadian dollar terms and to a year-end reduction in US reserves.

Accretion

	Three Months Ended June 30			Six Months Ended June 30		
(000's Cdn. $)	**2015**	**2014**	% Change	**2015**	2014	% Change
Accretion	**284**	461	(38)	**574**	767	(25)
Per boe	**0.81**	1.18	(31)	**0.80**	1.01	(20)

Accretion is the increase or decrease, 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 the first six months of 2015 decreased by 25% from the first six months in 2014. The 2014 six month period included expenditures to decommission certain wells over and above the decommissioning provision recorded.

Share-based Compensation

(000's Cdn. $)	Three Months Ended June 30 **2015**	2014	% Change	Six Months Ended June 30 **2015**	2014	% Change
Share-based compensation expense (recovery)						
Cash portion	**125**	-	-	**125**	-	-
Non-cash portion	**77**	816	(91)	**(911)**	1,736	(153)
	202	816	(75)	**(786)**	1,736	(145)
Share-based compensation expense (recovery)						
Cash portion - $ per Boe	**0.36**	**-**	-	**0.17**	-	-
Non-cash portion - $ per Boe	**0.22**	2.09	(89)	**(1.27)**	2.28	(156)
$ Per boe	**0.58**	2.09	(72)	**(1.10)**	2.28	(148)

The Company has determined that, in certain circumstances, it will cash settle stock options and a portion of the Company's share awards. The Company has recorded an incentive (share-based) compensation liability of $292,464 related to these cash settled instruments. Currently no options are in the money.

As a result of changes to the Company's share price, 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 change in fair value of the Company's shares resulted in an expense related to share-based compensation in the current quarter of $202,362 resulting in a six month period recovery of $786,098. No share-based compensation has been capitalized during 2015 or 2014.

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.

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.

On June 19, 2014, the Company issued 126,600 restricted awards and 114,600 performance awards to directors, officers and employees. The first vesting of the share incentive awards issued on June 19, 2015 occurred. The payout multiplier for the performance awards 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 June 30, 2015, the Company had 663,837 options outstanding at a weighted average strike price of $5.67 per share. Of these outstanding options, 573,007 are exercisable at a weighted average strike price of $5.92.

Foreign Exchange

	Three Months Ended June 30			Six Months Ended June 30		
(000's Cdn. $)	**2015**	2014	% Change	**2015**	2014	% Change
Realized loss (gain)	13	(156)	108	**(10)**	263	104
Unrealized loss (gain)	**512**	1,169	56	**(2,685)**	(134)	(1,904)
Total foreign exchange loss (gain)	**525**	1,013	48	**(2,695)**	129	2,189
Foreign exchange per Boe realized loss (gain)	**0.04**	(0.40)	109	**(0.01)**	0.35	104
Foreign exchangeb per Boe unrealized loss (gain)	**1.46**	2.99	51	**(3.75)**	(0.18)	(2,027)
	1.50	2.59	42	**(3.76)**	0.17	2,318

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

Sale of Properties

	Three Months Ended June 30			Six Months Ended June 30		
(000's Cdn. $)	**2015**	2014	% Change	**2015**	2014	% Change
(Gain) loss on sale of property	**1,449**	**-**	-	**1,449**	-	-
Per boe	**4.14**	**-**	-	**2.02**	**-**	-

During Q2 2015, the Company sold properties recording a loss on the sale of $1.4 million. The Company has sold and 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.

Provision for Income Taxes

	Three Months Ended June 30			Six Months Ended June 30		
(000's Cdn. $)	**2015**	**2014**	% Change	**2015**	2014	% Change
Current tax expense	**84**	336	(75)	**137**	507	(73)
Deferred tax expense	**(686)**	907	(176)	**(1,868)**	1,894	(199)
Total	**(602)**	1,243	(148)	**(1,731)**	2,401	(172)
$ Per Boe - current	**0.24**	0.86	(72)	0.19	0.67	(71)
$ Per Boe - deferred	**(1.96)**	2.32	(184)	(2.61)	2.49	(205)
$ Per boe - Total	**(1.72)**	3.18	(154)	(2.42)	3.16	(177)

For the six months ended June 30, 2015, the Company recorded income tax recovery of $1.7 million. In Canada, the six month 2015 loss totaled $2.9 million and the US recorded a six month loss of $2.7 million before income tax.

In Canada, the Company has not recorded any recovery of income tax as the Company has accumulated losses from Canadian operations and has Canadian tax pools in excess of $90 million at June 30, 2015. The Company has recognized a portion of the premium related to the issuance of flow-through shares in 2014. The Company incurred flow-through expenditures in the 2015 six month period of approximately $5.2 million recognizing $677,800 of the recorded premium. The Company has a long term liability (flow-through share issue premium) of $950,335 related to approximately $6.8 million of remaining qualifying expenditures required to be incurred by December 31, 2015.

In the US, the Company has recorded income tax recovery of $1.1 million of which $1.2 million represents a recovery of income tax and $136,716 represents current tax payable relating to Alternate Minimum Tax ("AMT" see below).

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.

At June 30, 2015, the deferred tax liability recorded in the Company's Statement of Financial Position of $20.7 million relates entirely to the US operations.

Net Income (Loss) per Boe

	Three Months Ended June 30		Six Months Ended June 30	
($Cdn.)	**2015**	2014	**2015**	2014
Oil and gas revenue	46.59	79.12	42.12	76.95
Royalties	(8.90)	(17.54)	(9.33)	(16.14)
Operating and transportation	(14.50)	(20.89)	(15.46)	(21.09)
Operating netback per Boe	**23.19**	40.69	**17.33**	39.72
Realized gain (loss) on risk management contracts	(0.18)	(5.76)	18.24	(4.99)
Realized gain on foreign exchange	(0.04)	0.40	0.01	0.35
General and administrative	(3.28)	(2.94)	(3.14)	(2.81)
Share-based compensation - cash portion	(0.36)	-	(0.17)	-
Interest and other financing charges	(1.49)	(1.80)	(1.48)	(1.80)
Current tax expense	(0.24)	(0.86)	(0.19)	(0.67)
Funds from operations netback per Boe	**17.60**	29.72	**30.60**	29.81
Unrealized gain (loss) on risk management contracts	(0.60)	0.13	(17.32)	(1.83)
Unrealized gain on foreign exchange	(1.46)	(2.99)	3.75	(0.18)
Depletion and depreciation	(19.62)	(18.97)	(19.98)	(18.64)
Accretion	(0.81)	(1.18)	(0.80)	(1.01)
Exploration and evaluation - directly expensed	(2.50)	(3.27)	(3.55)	(2.52)
Gain (loss) on sale of property and equipment	(4.14)	0.00	(2.02)	-
Share-based compensation -- non-cash portion	(0.22)	(2.09)	1.27	(2.28)
Deferred income tax	1.96	(2.32)	2.61	(2.49)
Net income (loss) per Boe	**(9.80)**	(0.96)	(5.44)	0.86

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 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.

Net Cash from Operating Activities, Funds from Operations and Net Income (Loss)

	Three Months Ended June 30			Six Months Ended June 30		
(000's Cdn. $ except per share amounts)	**2015**	2014	Change	**2015**	2014	Change
Net cash from operating activities	**2,405**	6,619	(64)	**19,514**	14,248	37
Funds from operations	**6,159**	11,610	(47)	**21,919**	22,663	(3)
Per share						
Basic	**0.34**	0.72	(52)	**1.22**	1.41	(13)
Diluted	**0.34**	0.71	(53)	**1.20**	1.39	(14)
Net income (loss)	**(3,429)**	(376)	(813)	**(3,895)**	652	(697)
Per share						
Basic	**(0.19)**	(0.02)	(720)	**(0.22)**	0.04	(637)
Diluted	**(0.19)**	(0.02)	(720)	**(0.22)**	0.04	(637)

Weighted Average Shares Outstanding

	Three Months Ended June 30			Six Months Ended June 30		
(000's Cdn. $ except per share amounts)	**2015**	**2014**	Change	**2015**	**2014**	Change
For Net (Loss) / Income Purposes						
Basic	17,907	16,085	11	17,896	16,088	11
Diluted	17,907	16,085	11	17,896	16,088	11
For Funds from Operations Purposes						
Basic	17,907	16,085	11	17,896	16,088	11
Diluted	18,302	16,327	12	18,291	16,329	12

Funds from operations (after realized commodity contract losses) for Q2 2015 totaled $6.2 million ($0.34 per share basic and diluted) versus funds from operations in Q1 2015 of $15.8 million ($0.88 per share basic and $0.87per share diluted) and $11.6 million ($0.72 per share basic and $0.72 per share diluted) in Q2 2014.

Funds from operations in Q2 2015 decreased from Q1 2015 as Q1 2015 included a realized gain on the monetization of crude commodity contracts of $13.2 million. The decrease in Q2 2015 from Q2 2014 is primarily price related. Average commodity prices received dropped 41% in Q1 2015 from Q2 2014 thereby reducing the operating netback by $25.70 per Boe to $17.33 per Boe.

Funds from operations for the six months ended June 30, 2015 totaled $21.9 million ($1.22 per share basic and $1.20 per share diluted) versus funds from operations in the 2014 six month period of $22.7 million ($1.41 per share basic and $1.39 per share diluted). Lower commodity prices reduced the operating netback by $17.8 million. This was offset by the realized gain on the monetization on crude commodity contracts in Q1 2015 versus a realized loss in the 2014 six month period.

On a Boe basis, funds from operations for Q2 2015 decreased to $17.60 per Boe versus $43.02 for Q1 2015 and $29.72 for Q2 2014 and for the six months ended June 30, 2015 increased to $30.60 per Boe versus $28.91 per Boe in the 2014 six month period. Lower prices leading to lower margins were offset by realized gains on crude commodity contracts.

The Company recorded a net loss for the six months ended June 30, 2015 of $3.9 million or $0.22 per share basic and diluted versus income of $652,361 or $0.04 per share basic and diluted in the 2014 six month period. Due to lower commodity prices, the operating margin declined by $17.9 million, 56% or $22.39 per Boe. In addition, the Company recorded a loss on the sale of properties of $1.4 million. Offsetting these items was a recovery of share-based compensation, a gain on foreign exchange and an income tax recovery.

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 gain of $2.5 million. Comprehensive loss therefore for the six months ended June 30, 2015 was $1.4 million versus comprehensive income of $602,483 for the six months ended June 30, 2014.

Summary of Quarterly Results

	2015		2014				2013	
(000's Cdn. $)	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Production (Boe)								
Total	349,956	366,349	435,344	445,997	390,583	369,746	372,410	397,702
Per day	3,846	4,071	4,732	4,848	4,292	4,108	4,048	4,323
Oil and gas revenue	16,305	13,866	25,210	33,322	30,902	27,606	24,112	30,177
Funds from operations	6,159	15,760	16,906	14,994	11,610	11,053	9,013	11,695
Per share - basic ($)	0.34	0.88	0.98	0.89	0.72	0.69	0.56	0.73
- diluted ($)	0.34	0.87	0.95	0.88	0.71	0.69	0.56	0.72
Net income (loss)	(3,429)	(466)	15,367	9,622	(376)	1,028	(396)	(627)
Per share - basic ($)	(0.19)	(0.03)	0.89	0.89	(0.02)	0.06	(0.02)	(0.04)
- diluted ($)	(0.19)	(0.03)	0.81	0.81	(0.02)	0.06	(0.02)	(0.04)
Total assets	228,147	230,571	236,424	223,262	211,996	202,146	191,922	191,000
Total debt (1)	56,635	57,229	65,198	81,230	84,417	74,294	70,422	69,147
Shares outstanding	17,969	17,897	17,877	16,974	16,074	16,090	16,080	16,070

(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 Evi, the rationalization of properties and operating costs and in the past two 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

For the Three Months Ended June 30, 2015 (000's Cdn. $)	Canada	U.S	Total
Production (Boe/d)	2,481	1,365	**3,846**
Oil and gas revenue	9,572	6,733	**16,305**
Operating income	4,166	3,948	**8,114**
Funds from operations	3,816	2,343	**6,159**
Income (loss) before income taxes	(2,927)	(1,104)	**(4,031)**
Net income (loss) for the year	(2,738)	(691)	**(3,429)**
Exploration and evaluation assets (as at June 30, 2015)	3,139	-	**3,139**
Property, plant and equipment (as at June 30, 2015)	104,647	105,040	**209,687**
Property, plant and equipment expenditures	1,383	4,652	**6,035**
Exploration and evaluation expenditures	-	-	**-**
Exploration and evaluation expenses	877	-	**877**
Property dispositions	(1,677)	-	**(1,677)**
Property acquisitions	-	-	**-**

For the Three Months Ended June 30, 2014 (000's Cdn. $)	Canada	U.S	Total
Production (Boe/d)	2,765	1,527	**4,292**
Oil and gas revenue	17,927	12,975	**30,902**
Operating income	7,944	7,948	**15,892**
Funds from operations	6,665	4,945	**11,610**
Income (loss) before income taxes	(11,673)	2,440	**(9,233)**
Net income (loss) for the year	(1,572)	1,196	**(376)**
Exploration and evaluation assets (as at June 30, 2014)	10,142	-	**10,142**
Property, plant and equipment (as at June 30, 2014)	95,808	87,812	**183,620**
Property, plant and equipment expenditures	4,528	12,700	**17,228**
Exploration and evaluation expenditures	223	-	**223**
Exploration and evaluation expenses	1,276	-	**1,276**
Property dispositions	-	-	**-**
Property acquisitions	-	-	**-**

For the Six Months Ended June 30, 2015 (000's Cdn. $)	Canada	U.S	Total
Production (Boe/d)	2,481	1,365	**3,846**
Oil and gas revenue	17,015	13,156	**30,171**
Operating income	4,983	7,431	**12,414**
Funds from operations	17,523	4,396	**21,919**
Income (loss) before income taxes	(2,897)	(2,729)	**(5,626)**
Net income (loss) for the year	(2,219)	(1,676)	**(3,895)**
Exploration and evaluation assets (as at June 30, 2015)	3,139	-	**3,139**
Property, plant and equipment (as at June 30, 2015)	104,647	105,040	**209,687**
Property, plant and equipment expenditures	5,153	7,553	**12,706**
Exploration and evaluation expenditures	-	-	**-**
Exploration and evaluation expenses	2,543	-	**2,543**
Property dispositions	(1,677)	-	**(1,677)**
Property acquisitions	-	-	**-**

For the Three Months Ended June 30, 2014 (000's Cdn. $)	Canada	U.S	Total
Production (Boe/d)	2,765	1,527	**4,292**
Oil and gas revenue	17,927	12,975	**30,902**
Operating income	7,944	7,948	**15,892**
Funds from operations	6,665	4,945	**11,610**
Income (loss) before income taxes	(11,673)	2,440	**(9,233)**
Net income (loss) for the year	(1,572)	1,196	**(376)**
Exploration and evaluation assets (as at June 30, 2014)	10,142	-	**10,142**
Property, plant and equipment (as at June 30, 2014)	95,808	87,812	**183,620**
Property, plant and equipment expenditures	4,528	12,700	**17,228**
Exploration and evaluation expenditures	223	-	**223**
Exploration and evaluation expenses	1,276	-	**1,276**
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 Princess and Provost, 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, 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.

Net 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 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. The annualized funds from operations is further adjusted, if required, for large one-time items included in the recent quarter.

The Company's net debt to annualized funds from operations ratio at June 30, 2015 is 2.30 : 1.

The Company's net debt to equity ratio at June 30, 2015 is 0.64: 1.

The Company expects to focus its future capital expenditure program on drilling exploratory wells in Alberta at Princess and Provost. The Company expects its US commitment at Lindahl, North Dakota for 2015 to be substantially completed. The remaining capital program is somewhat flexible and is designed to ensure that the Company meets all of its 2014 flow-through commitments, to build development drilling for when prices and margins improve and to retain our interest in our US drilling inventory.

Net Debt and Debt to Annualized Funds from Operations

(000's Cdn. $)	June 30, 2015
Bank loan	56,000
Working capital deficiency (1)	635
Total debt	56,635
Annualized funds from operations	24,636
Net debt to annualized funds flow ratio	**2.30**

(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 current and included under bank loan. The Company maintains sufficient unused bank credit facility to ensure any working capital deficiency can be funded.

Net Debt Reconciliation

(000's Cdn. $)	**Six Months Ended June 30**
Net debt December 31, 2014	**65,198**
Funds from operations	**(21,919)**
Additions to property, plant and equipment	**12,706**
Exploration and evaluation expenses	**2,543**
Dividends	**775**
Cash portion of share incentive awards settled	**125**
Decommissioning liabilities settled	**171**
Proceeds on sale of properties	**(1,677)**
Foreign exchange gain on US cash held	**(135)**
Change in working capital and other items	**(1,152)**
Net debt June 30, 2015	**56,635**

Debt to Equity Ratio

(000's Cdn. $)	June 30, 2015
Shareholders' Equity	88,925
Debt to equity	**0.64**

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

The Company has not adjusted its approach to capital management during Q2.

Credit Facility

The Company's credit facility was reviewed in May 2015 based on the Company's yearend engineering report prepared by an independent petroleum engineer. Based on the reserves as determined in the engineering report and applying the price deck as provided by the syndicate, the new borrowing base was revised to $55.0 million. A semi-annual review of the borrowing base is to be completed on or before November 30, 2015. The credit facility included a $45.0 million Extendable Syndicated Credit Facility, a $10.0 million Extendable Operating Credit Facility and a $15.0 million Supplemental Credit Facility (together the "Facility").

The Supplemental Credit Facility, available by way of a single advance on the effective date, was drawn at $12.0 million, is required to be repaid by May 31, 2016 and 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.

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 $12.0 million on the Supplemental Credit Facility commenced on May 28, 2015.

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) in excess of $1.5 million until May 31, 2016 and in excess of $5.0 million annually thereafter.

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 June 30, 2015, the Company was in compliance with this and all other covenants as required under the agreement.

At June 30, 2015, debt under the Facility amounted to $56.0 million (December 31, 2014 - $60.0 million) of which $12.0 million was outstanding under the Supplemental Credit Facility. Net debt (after adjusting for working capital deficiency at June 30, 2015 was $56.6 million (December 31, 2014 - $65.2 million) (June 30, 2014 - $84.4 million).

Subsequent to quarter end, the Supplemental Credit Facility was reduced by $3.0 million.

Liquidity

Crude prices started to decline in late 2014 to where we are trading now at WTI $46.00 US per barrel. This significant decline has had an adverse effect on the Company's operating margins and therefore on funds from operation and on capital available to be reinvested during the remainder of 2015 and in 2016. In addition, the decline in prices has had a negative impact on the Company's reserves that reduced the Company's borrowing base and therefore its credit facility.

In order to strengthen the Company's balance sheet, the Company monetized a portion of its crude hedge book in December 2014 and the remainder in January 2015 (these transactions reduced debt by approximately $16.1 million). In addition, the Company reduced the dividend from $0.07 per share in February 2015 to $0.03 and in May further reduced the dividend to $0.02 per share, reduced employee bonuses, froze salaries , reduced staff and undertook other initiatives to reduce capital, operating and general and administrative expenditures. In July 2015, the Company further reduced debt as it closed a bought deal private placement for gross proceeds of $4.6 million.

With these initiatives and the Company's current production base continuing to generate positive margins and cash flow, management believes that they have positioned the Company to c preserve value for shareholders and have aligned funds from operations with capital expenditures and dividends. The Company will continue to exercise a disciplined approach to its payout ratio with an effort to maintain financial strength and flexibility while utilizing a prudent use of debt.

Dividends

In August 2013, the Board of Directors adopted a dividend policy, approving a quarterly dividend payment to shareholders of approximately 10% of the Company's trailing cash flow as adjusted for significant one-time cash inflows or outflows and current economic conditions, factors and expectations.

In June 2014, shareholders approved a special resolution authorizing certain amendments to the Articles of the Company to permit the payment of share dividends on common shares to shareholders electing to receive dividends in common shares of the Company. Shareholders wishing to participate in the Share Dividend Plan should contact their broker or intermediary or, in the case of registered shareholders, contact our transfer agent, Alliance Trust Company, or visit our website to obtain the necessary enrolment forms.

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	386,654	To Be Determined	

Share Capital

Common Shares

(000's)	**Shares**	**Period Ended June 30, 2015 $**	Shares	Year Ended December 31, 2014 $
Balance - beginning of period	**17,877**	**151,434**	16,080	137,705
Issued under private placements	**-**	-	1,712	16,558
Share issue costs	**-**	-	-	(3,715)
Issued on exercise of options	-	-	101	877
Issued pursuant to share dividend program	**32**	**119**	42	358
Purchases under normal course issuer bid	**-**	-	(41)	(349)
Issued on vesting of Share Award Incentive Plan	**60**	**398**		
Cancelled on expiration of amalgamation exchange provision	**-**	-	(17)	-
Balance - end of period	**17,969**	**151,951**	17,877	151,434

In February (19,489) and in May (12,325) of 2015, the Company issued 31,814 common shares in relation to the share dividend program.

In June, the Company issued 59,460 commons shares pursuant to the Company's Share Award Incentive Plan (see below).

On July 12, 2015 the Company closed a "bought deal' private placement and issued 778,460 common shares at a price of $3.15 per common share and 585,700 flow-through common shares at a price of $3.70 per flow-through common share for gross proceeds of $4.6 million.

The Company will use the proceeds of the common share portion of the Offering to pay down existing indebtedness to position the Company to take advantage of property dispositions by competitors in its core areas and will use the proceeds of the flow-through common shares to incur eligible Canadian Exploration Expenses on its core properties and renounce such expenses to subscribers of these shares effective for the 2015 tax year. The expenses must be incurred by December 31, 2016.

Options

(000's)	**Period Ended June 30, 2015**	Year Ended December 31, 2014
Balance - beginning of period	**1,014**	1,268
Exercised	**-**	(101)
Option "puts" cash settled by the Company	**-**	(148)
Cancelled (forfeited or expired unexerecised)	**(350)**	(5)
Balance - end of period	**664**	1,014

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, 2015		**Year Ended December 31, 2014**	
(000's)	**Restricted**	**Performance**	**Restricted**	**Performance**
Balance - beginning of period	**127**	**115**	-	-
Awards isued	**124**	**117**	127	115
Cancelled (forfeited or expired unexerecised)	**(11)**	**(6)**	-	-
Adjustment for dividends	**4**	**3**	-	-
Adjustment for performance factor	**-**	**19**	-	-
Vested and converted into common shares	**(25)**	**(35)**	-	-
Vested and paid in cash	**(16)**	**(21)**	-	-
Balance - end of period	**203**	**192**	127	115

At June 30, 2015, the Company has 17,968,546 common shares outstanding, 633,837 options outstanding at a weighted average price of $6.51 per share and 202,717 restricted share rights and 192,194 performance share rights awarded under the Share Award Incentive Plan outstanding.

As of the date of this MD&A, the Company has 19,332,706 common shares outstanding, 663,837 options outstanding and 202,717 restricted share award and 192,194 performance share award outstanding.

Capital Expenditures

Capital expenditures for Q2 2015 to property, plant and equipment totaled $6.0 million down from $17.2 million in Q2 2014. Expenditures in Q2 2015 were incurred in Canada ($1.4 million) primarily on completions and on equipment and facilities at Princess. Expenditures were incurred in the US, ($4.6 million) primarily to complete and equip wells at Lindahl.

For the six months ended June 30, 2015, capital expenditures totaled $12.7 million down from $29.1 million in the six months ended June 30, 2014. In Canada, the Company spent $5.2 million versus $8.1 million and in the US versus spent

$7.6 million versus $21.1 million. Expenditures in Canada were on land purchases, completions and well equipment and on facilities at Evi and Princess and in the US on drilling, completions and well equipment at Lindahl.

During the quarter, the Company disposed of a small portion of its Blackstone property carried under exploration and evaluation assets for proceeds of $500,000 and an isolated piece of property in the Provost area for proceeds of $1.2 million.

During the six month period ended June 30, 2015, the Company shot seismic and incurred certain evaluation and interpretation expenditures totaling $2.5 million in the Princess, Cessford and Provost areas of Alberta

Total Company

Property, Plant and Equipment Expenditures

	Three Months Ended June 30		Six Months Ended June 30	
(000's Cdn. $)	**2015**	**2014**	**2015**	**2014**
Land	**(120)**	308	**192**	553
Drilling and completions	**4,737**	13,734	**8,539**	23,499
Capitalized general and administrative	**150**	225	**325**	387
Production equipment, facilities and tie-ins	**1,268**	2,939	**3,650**	4,645
Other	**17**	1,591	**583**	1,370
Total property plant and equipment additions	**6,052**	18,797	**13,289**	30,454
Non-cash additions	**(17)**	(1,569)	**(583)**	(1,313)
Total Property, Plant and Equipment Expenditure	**6,035**	17,228	**12,706**	29,141

Exploration and Evaluation Expenditures

	Three Months Ended June 30		Six Months Ended June 30	
(000's Cdn. $)	**2015**	**2014**	**2015**	**2014**
Land	-	**(3)**	-	207
Drilling and completions	-	**226**	-	292
Total Exploration and Evaluation Expenditures	-	223	-	499

Property Acquisitions

	Three Months Ended June 30		Six Months Ended June 30	
(000's Cdn. $)	**2015**	**2014**	**2015**	**2014**
Total Property Acquisitions	**-**	-	**-**	152

Property Dispositions

	Three Months Ended June 30		Six Months Ended June 30	
(000's Cdn. $)	**2015**	**2014**	**2015**	**2014**
Total Property Dispositions	**(1,677)**	-	**(1,677)**	-

Exploration and Seismic Expenses

	Three Months Ended June 30		Six Months Ended June 30	
(000's Cdn. $)	**2015**	**2014**	**2015**	**2014**
Seismic expenditures	**845**	871	**2,511**	1,515
Other	**32**	405	**32**	405
Total Exploration nad Seismic Expenses	**877**	1,276	**2,543**	1,920

CANADA

Property, Plant and Equipment Expenditures

(000's Cdn. $)	Three Months Ended June 30 2015	Three Months Ended June 30 2014	Six Months Ended June 30 2015	Six Months Ended June 30 2014
Land	**-**	163	**209**	163
Drilling and completions	**339**	3,118	**1,763**	4,872
Capitalized general and administrative	**150**	225	**325**	387
Production equipment, facilities and tie-ins	**893**	1,000	**2,855**	2,593
Other	**17**	10	**576**	(236)
Total property plant and equipment additions	**1,399**	4,516	**5,728**	7,779
Non-cash additions	**(17)**	12	**(576)**	293
Total Property, Plant and Equipment Expenditures	**1,382**	4,528	**5,152**	8,072

Exploration and Evaluation Expenditures

(000's Cdn. $)	Three Months Ended June 30 2015	Three Months Ended June 30 2014	Six Months Ended June 30 2015	Six Months Ended June 30 2014
Land	-	(3)	-	207
Drilling and completions	-	226	-	292
Total Exploration and Evaluation Expenditures	-	223	-	499

Property Dispositions

(000's Cdn. $)	Three Months Ended June 30 2015	Three Months Ended June 30 2014	Six Months Ended June 30 2015	Six Months Ended June 30 2014
Total Property Dispositions	**(1,677)**	-	**(1,677)**	-

Exploration and Seismic Expenses

(000's Cdn. $)	Three Months Ended June 30 2015	Three Months Ended June 30 2014	Six Months Ended June 30 2015	Six Months Ended June 30 2014
Seismic expenditures	**845**	871	**2,511**	1,515
Other	**32**	405	**32**	405
Total Exploration nad Seismic Expenses	**877**	1,276	**2,543**	1,920

USA

Property, Plant and Equipment Expenditures

(000's Cdn. $)	Three Months Ended June 30 2015	Three Months Ended June 30 2014	Six Months Ended June 30 2015	Six Months Ended June 30 2014
Land	**(120)**	145	**(17)**	390
Drilling and completions	**4,398**	10,616	**6,776**	18,627
Capitalized general and administrative	**-**	-	**-**	-
Production equipment, facilities and tie-ins	**375**	1,939	**795**	2,052
Other	**-**	1,581	**7**	1,606
Total property plant and equipment additions	**4,653**	14,281	**7,561**	22,675
Non-cash additions	**-**	(1,581)	**(7)**	(1,606)
Total Property, Plant and Equipment Expenditures	**4,653**	12,700	**7,554**	21,069

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 June 30, 2015**	Year Ended December 31, 2014
Total decommissioning obligations at beginning of year	**44,729**	36,321
Obligations settled	**(171)**	(1,987)
Obligations disposed of	**(391)**	(36)
Obligations incurred	**550**	646
Change in estimate	**34**	7,601
Foreign currency translation	**527**	431
Accretion expense	**574**	1,753
Total decommissioning obligations at end of period	**45,852**	44,729
Recorded as folows:		
Decommissioning obligations to be incurred within one year	**750**	750
Decommissioning obligations to be incurred beyond one year	**45,102**	43,979
Total decommissioning obligations at end of period	**45,852**	44,729

Commitments and Contingencies

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. Should any loss result from the resolution of these claims, such loss will be charged to operations in the period of resolution.

Future Accounting Policies:

The International Accounting Standards Board 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.

(a) IFRS 11 – Acquisitions of Interests in Joint Operations

(b) IFRS 15 – Revenue from Contracts and Customers

(c) IFRS 9 – Financial Instruments

Disclosure Controls and Procedures

There were no changes in disclosure controls and procedures during the interim period commencing April 1, 2015 and ending June 30, 2015.

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 April 1, 2015 and ending June 30, 2015.