MANAGEMENT DISCUSSION AND ANALYSIS

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 nine months ended September 30, 2009. It should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2008 and other operating and financial information contained herein. This MD&A is dated November 9, 2009.

The financial data presented herein has in part been derived from the Company's annual audited consolidated financial statements prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP") and in accordance with accounting policies as set out in Notes 3 and 4 to the Company's annual consolidated financial statements. The reporting currency is the Canadian dollar.

Additional information regarding Arsenal's financial and operating results may be obtained on the internet at www.sedar.com.

Forward-Looking Statements

Certain statements contained within the Management's Discussion and Analysis, and in certain documents incorporated by reference into this document, constitute forward looking statements. These statements relate to future events or our 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', 'project', 'predict', 'potential', 'targeting', 'intend', 'could', 'might', 'should', 'believe' and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward looking statements.

In particular, this MD&A contains the following forward-looking statements pertaining to, without limitation, the following: Arsenal's production volumes and the timing of when additional production volumes will come on stream; Arsenal's realized price of commodities in relation to reference prices; future commodity prices; the Company's future royalty rates and the realization of royalty incentives; the impact of the New Royalty Framework on the Company's future royalties; Arsenal's expectation of reducing operating costs on a per unit basis; the relationship of Arsenal's interest expense and the Bank of Canada interest rates; increases in general and administrative expenses and recoveries; future development and exploration activities and the timing thereof; the future tax liability of the Company; the expected decrease in the depletion, depreciation and accretion rate; the estimated future contractual obligations of the Company and the amount expected to be incurred under its farm-in commitments; the future liquidity and financial capacity of the Company; and its ability to fund its working capital and forecasted capital expenditures. In addition, statements relating to 'reserves' or 'resources' are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future.

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 and reserves through exploration and development activities; and the continuation of the current tax and regulation.

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, or incorporated by reference into, this MD&A should not be unduly relied upon. These statements speak only as of the date of this MD&A or as of the date specified in the documents incorporated by reference into this Management's Discussion and Analysis, as the case may be. 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 Management's Discussion and Analysis: volatility in market prices for oil and natural gas; counterparty credit risk; access to capital; changes or fluctuations in production levels; liabilities inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; stock market volatility and market valuation of Arsenal stock; geological, technical, drilling and processing problems; limitations on insurance; changes in environmental or legislation applicable to our operations, and our ability to comply with current and future environmental and other laws; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; and the other factors discussed under "Risk Factors" in the following annual MD&A. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward looking statements contained in this MD&A and the documents incorporated by reference herein 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 barrel of oil equivalent ("Boe" or "boe") using six thousand cubic feet ("Mcf") of natural gas to one barrel of oil unless otherwise stated. Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of six Mcf to one barrel ("Bbl") is based on an energy equivalency method primarily at the burner tip and does not represent a value equivalency at the wellhead. (This conversion conforms to National Instrument 51-101). References to natural gas liquids ("NGLs") in this MD&A include condensate, propane, butane and ethane and one barrel of NGLs is considered to be equivalent to one barrel of crude oil equivalent (Boe).

Non-GAAP Financial Measurements

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", "netbacks" and "netbacks per Boe" are not defined by GAAP in Canada and are regarded as non-GAAP measures. Funds from operations are determined by cash flow from operations before the change in non-cash operating working capital and asset retirement expenditures. Funds from operations should not be considered as an alternative to, or more meaningful than cash flow from operating activities as determined in accordance with GAAP as an indicator of the Company's performance. The Company's determination of funds from operations may not be comparable to that reported by other companies. Funds from operations per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of earnings per share.

The following table reconciles cash from operating activities to funds from operations which is used in the MD&A:

($Cdn.)	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Cash provided by operating activities	**3,114,799**	9,133,964	(66)	**14,089,419**	18,591,708	(24)
Asset retirement expenditures	**(30,413)**	(1,171)	2,497	**324,051**	39,756	715
Change in non-cash working capital	**(196,560)**	(1,039,636)	(81)	**821,348**	1,342,842	(39)
Funds from operations	**2,887,826**	8,093,157	(64)	**15,234,818**	19,974,306	(24)

Netbacks equal total revenue less royalties, operating costs and transportation, calculated on a commodity and Boe basis. Total Boe is calculated by multiplying the daily production by the number of days in the year or quarter as the case may be.

Tables may not add due to rounding.

Operational and Financial Highlights

In September 2009, the Company issued 8,750,000 flow-through shares ("FTS") at $0.40 per share for gross proceeds of $3,500,000. The proceeds were used initially to reduce debt. The Company is committed to incurring $3,500,000 of qualifying expenditures by December 31, 2010.

During the third quarter, the Company reduced its bank debt (see Credit Facility) by $3.8 million to $33.3 million at September 30, 2009 due to the initial application of the proceeds from the FTS issue, increased cash flow over Q2 2009 and the proceeds from a minor non-core property sale. In addition, the Company has an unrealized gain on its commodity contracts of $0.8 million at September 30, 2009.

During the third quarter, the Company sold a small non-core property for $0.3 million bringing year to date total sales proceeds from asset sales to $3.4 million. Production from these properties totaled less than 100 Boe per day.

In Q3 2009, the Company completed drilling two Bakken and one Three Forks well in North Dakota. The two Bakken wells drilled in the quarter went on production during the quarter and the Three Forks well was completed after quarter end. The Company expects to drill at least three additional Bakken wells (each at approximately 30% working interest) at Stanley, North Dakota in Q4 2009 or Q1 2010 spending approximately $6.3 million.

Arsenal's production for the third quarter of 2009 averaged 2,081 Boe per day versus 2,236 Boe per day in the second quarter and 2,330 Boe per day for the first quarter of 2009. The decline relates to the sale of non-core properties and wells shut-in for economic reasons. These wells are expected to be back on-production in Q4 2009.

Funds flow from operations for the third quarter of 2009 was $2.9 million or $0.03 per basic and diluted share compared to $8.1 million or $0.09 per basic and diluted share in Q3 2008. Lower commodity prices account for this decline.

During Q3 2009, no purchases were made by the Company under the Normal Course Issuer Bid announced in October 2008. The Normal course Issuer Bid expired in October 2009 with no further purchases.

Arsenal Energy Inc.'s common shares are listed and posted for trading on the Toronto Stock Exchange under the symbol "AEI" and on the Frankfurt Stock Exchange under the symbol "A1E".

The Company operates in the United States through its subsidiary, Arsenal Energy USA Inc., and produced an average of 596 Boe per day in Q3 2009 versus 440 Boe per day in Q2 2009 and 378 Boe per day in Q3 2008. In Canada, the Company operates under Arsenal Energy Inc., and produced an average of 1,485 Boe per day in Q3 2009 versus 1,796 Boe per day in Q2 2009 and 1,389 Boe per day in Q3 2008. The increase in the US relates to

Bakken drilling brought on-production. The increase in Canada quarter over comparable quarter relates to the acquisition of GEOCAN while the decrease over the prior quarter relates to properties either sold or temporarily shut-in and to production declines.

OPERATIONAL AND FINANCIAL RESULTS

SUMMARY OF OPERATING & FINANCIAL RESULTS				
	Three Months Ended September 30		Nine Months Ended September 30	
	2009	2008	**2009**	2008
FINANCIAL				
Oil and gas revenue	**9,252,597**	15,766,815	**26,860,608**	43,754,610
Funds from operations	**2,887,826**	8,093,157	**15,234,818**	19,974,306
Per share - basic and diluted	**0.03**	0.09	**0.15**	0.23
Net income (loss)	**(1,897,761)**	10,028,193	**(8,205,132)**	7,614,314
Per share - basic and diluted	**(0.02)**	0.11	**(0.08)**	0.09
Total debt (excluding derivatives)	**33,285,548**	13,384,766	**33,285,548**	13,384,766
Capital expenditures	**3,264,967**	7,432,941	**6,979,873**	17,110,739
Property acquisitions	**-**	-	**-**	974,733
Property dispositions	**(265,860)**	-	**(3,431,984)**	(1,235,792)
Corporate acquisitions				
Wells drilled (net)				
Oil	**0.66**	2.35	**1.01**	**13.70**
Gas	**-**	-	**-**	**-**
Dry	**-**	3.00	**-**	**5.00**
Shares outstanding - end of period	109,961,890	90,786,148	**109,961,890**	90,786,148
OPERATIONAL				
Daily production				
Heavy oil (bbl/d)	**668**	578	**766**	640
Light oil and NGLs (bbl/d)	**858**	920	**830**	821
Natural gas (mcf/d)	**3,327**	1,619	**3,718**	2,029
Oil equivalent (boe @ 6:1)	**2,081**	1,767	**2,215**	1,800
Realized commodity prices ($Cdn.)				
Heavy oil (bbl)	**59.93**	98.36	**51.88**	85.65
Light oil and NGLs (bbl)	**59.31**	110.34	**53.39**	106.05
Natural gas (mcf)	**2.90**	8.07	**3.87**	8.76
Oil equivalent (boe @ 6:1)	**48.33**	97.00	**44.42**	88.72
Reference pricing				
WTI (U.S.$/bbl)	**68.18**	118.36	**56.86**	113.43
Heavy Oil Lloyd blend ($Cdn./bbl)	**71.70**	122.77	**62.68**	115.85
AECO (daily spot) ($Cdn./mcf)	**2.99**	8.02	**3.88**	**8.72**
Foreign exchange ($U.S./$Cdn.)	**0.91**	**0.96**	**0.85**	**0.98**
Operating netback ($ per boe)				
Revenue	**48.33**	97.00	**44.42**	88.72
Royalty	**(8.93)**	(21.57)	**(8.76)**	(17.66)
Operating cost	**(16.78)**	(18.39)	**(16.95)**	(20.90)
Transportation cost	**(1.04)**	-	**(1.05)**	-
Operating netback per boe	**21.58**	57.04	**17.66**	50.15

PRODUCTION AND REVENUE

Average Daily Production

The Company has production in the provinces of British Columbia, Alberta and Saskatchewan in Canada (71% of total Q3 2009 production) and in the state of North Dakota in the US (29% of total Q3 2009 production). The US production is expected to increase over time as a percentage of total production as the Company continues to drill Bakken oil wells in North Dakota.

Production for the third quarter of 2009 averaged 2,081 Boe per day versus 1,767 Boe per day in the third quarter of 2008. Production for the nine month period increased from 1,800 Boe per day in 2008 to 2,215 Boe per day for 2009.

The increase in production for the quarter and for the nine month period is primarily attributed to the acquisition of GEOCAN in October 2008 and increased production volumes from the Company's Bakken wells in North Dakota. Normal production declines and production from wells sold or shut-in were offset by 2008 drilling at Evi, Alderson and Galahad and 2009 drilling at Stanley and Lindahl in North Dakota.

With the acquisition of GEOCAN in late 2008 natural gas production increased as a percentage of total production.

Production Profile and Per Unit Prices

Production	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Heavy oil (bbl/d)	**668**	578	16	**766**	**640**	20
Light oil and NGLs (bbl/d)	**858**	920	(7)	**830**	**821**	1
Natural gas (mcf/d)	**3,327**	1,619	106	**3,718**	**2,029**	83
Total (boe/d)	**2,081**	1,767	18	**2,215**	1,800	23
Production split						
Heavy oil	**32%**	33%	(2)	**35%**	36%	(3)
Light oil and NGLs	**41%**	52%	(21)	**37%**	46%	(18)
Natural gas	**27%**	15%	75	**28%**	19%	49

Crude oil is sold under 30-day evergreen contracts while natural gas production is sold in the spot market.

The Company received an average price per Boe during Q3 2009 of $48.33 per Boe a decrease of 50% from $97.00 per Boe received during Q3 2008. For the nine month period, the average price per Boe also declined 50% to $44.42 per Boe from $88.72 per Boe.

The decreases in commodity prices received by the Company are reflective of the decline in commodity prices over the comparative periods. Commodity prices began increasing during Q1 2008 peaking in Q3 2008 and declining thereafter to bottom during the first half of 2009. Prices currently have improved and if they remain at current levels, average price received per Boe should improve in Q4 2009.

Production by Area

AREA	Three Months Ended September 30 2009 Boe/d	2009 % of Total	2008 Boe/d	2008 % of Total	Nine Months Ended September 30 2009 Boe/d	2009 % of Total	2008 Boe/d	2008 % of Total
Canada								
Maidstone (heavy oil)	**-**	**-**	188	11	**59**	**3**	184	10
Galahad (light oil and solution gas)	**175**	**8**	286	16	**194**	**9**	236	13
Wildmere (heavy oil)	**93**	**4**	113	6	**108**	**5**	121	7
Chauvin/Ribstone (GEOCAN)	**316**	**15**	-	-	**316**	**14**	-	-
West Current (GEOCAN)	**130**	**6**	-	-	**132**	**6**	-	-
Evi (light oil)	**105**	**5**	302	17	**135**	**6**	286	16
Others	**666**	**32**	500	28	**766**	**35**	586	33
Total Canada	**1,485**	**71**	1,389	79	**1,710**	**77**	1,413	79
US								
Stanley (light oil)	**314**	**15**	122	7	**227**	**10**	121	7
Lindahl (light oil)	**86**	**4**	68	4	**76**	**3**	72	4
Tioga (light oil)	**60**	**3**	56	3	**51**	**2**	56	3
Others	**136**	**7**	132	7	**151**	**7**	138	8
Total US	**596**	**29**	378	21	**505**	**23**	387	22
Total boe/d production	**2,081**	**100**	1,767	100	**2,215**	**100**	1,800	100

As a result of the GEOCAN acquisition, the percentage of oil and natural gas production originating in Canada increased quarter over comparative quarter and for the comparative nine month periods. Due to the ongoing development of Arsenal's high impact Bakken play in North Dakota it is expected that the percentage of production from the US will increase in the future.

Oil and Gas Revenue

Prices

($Cdn.)	Three Months Ended September 30			Nine Months Ended September 30		
Prices - Before Commodity Contracts	**2009**	2008	% Change	**2009**	2008	% Change
Heavy oil (bbl)	**59.93**	98.36	(39)	**51.88**	85.65	(39)
Light oil and NGLs (bbl)	**59.31**	110.34	(46)	**53.39**	106.05	(50)
Natural gas (mcf)	**2.90**	8.07	(64)	**3.87**	8.76	(56)
Total (boe)	**48.33**	97.00	(50)	**44.42**	88.72	(50)

($Cdn.)	Three Months Ended September 30			Nine Months Ended September 30		
Reference Pricing	**2009**	2008	% Change	**2009**	2008	% Change
WTI Cushing ($U.S./bbl)	**68.18**	118.36	(42)	**56.86**	113.43	(50)
Oil Edmonton Light ($Cdn./bbl)	**71.70**	122.77	(42)	**62.68**	115.85	(46)
Heavy Oil Lloyd blend ($Cdn./bbl)	**63.71**	103.76	(39)	**55.57**	94.38	(41)
AECO (daily spot) ($Cdn./mcf)	**2.99**	8.02	(63)	**3.88**	8.72	(56)
NYMEX (Henry Hub) gas ($U.S./mmbtu)	**3.40**	10.26	(67)	**3.96**	9.74	(59)
Foreign exchange ($Cdn./$U.S.)	**0.91**	**0.96**	(5)	**0.85**	0.98	(13)

Revenue

($Cdn.)	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Heavy oil	**3,685,054**	5,225,716	(29)	**10,845,647**	15,030,167	(28)
Light oil and NGLs	**4,679,686**	9,339,442	(50)	**12,091,817**	23,853,116	(49)
Natural gas	**887,857**	1,201,657	(26)	**3,923,144**	4,871,327	(19)
Oil and gas revenues	**9,252,597**	15,766,815	(41)	**26,860,608**	43,754,610	(39)
Gain (loss) on commodity contracts	**1,402,041**	9,283,279	(85)	**978,624**	1,599,452	(39)
Oil and gas revenue after commodity contracts	**10,654,638**	25,050,094	(57)	**27,839,232**	45,354,062	(39)
Per Boe before commodity contracts	**48.33**	97.00	(50)	**44.42**	88.72	(50)
Per Boe after commodity contracts	**55.65**	154.11	(64)	**46.04**	91.96	(50)

Total petroleum and natural gas revenues in Q3 2009 decreased 41% to $9,252,597 from Q3 2008 and decreased 4% from Q2 2009 ($9,638,098). The Q3 2009 decrease from Q3 2008 is due to the 50% decrease in the average price per Boe received before commodity price contracts as production over the comparative periods increased 18%. The production increase was not sufficient to offset the significant price reductions realized over the comparative periods. The decrease in revenues from Q2 2009 was due to property sales and shut-in production. As prices have improved recently, the Company has brought some of the shut-in production back on-stream.

Total petroleum and natural gas revenues for the period ended September 30, 2009 decreased 39% to $26,860,608 from the 2008 period ($43,754,610). This decrease is attributed to a reduction of 50% or $44.30 per Boe over the comparative periods. This price reduction offset a 23% increase in average production over the period.

The Company recorded a gain of $1,402,041 ($7.32 per Boe) on its commodity contracts resulting in a year to date gain of $978,624 ($1.62 per Boe) of which $834,307 is unrealized as it relates to future deliveries. The price the Company ultimately realizes on its commodity contracts fluctuates with the price of WTI and changes in the Cdn/US exchange rate.

The following table details the financial commodity contracts the Company has in-place as at September 30, 2009 and fair value of those contracts recorded in the financial statements as at September 30, 2009.

($Cdn.)

Commodity Sold	Notional Volume	Remaining Term	Pricing	Fair Value
Natural Gas	1,000 GJ per day	Jan 1, 2010 - Dec 31, 2010	6.78 per GJ	375,317
Natural Gas	1,000 GJ per day	Nov 1, 2009 - Mar 31, 2010	5.50 per GJ	11,699
Oil	100 bbl per day	Oct 1, 2009 - Apr 30, 2010	72.60 per bbl	(93,310)
Oil	100 bbl per day	May 1, 2010 - Apr 30, 2011	79.50 per bbl	(55,821)
Oil	400 bbl per day	Oct 1, 2009 - Dec 31, 2009	81.50 per bbl	201,552
Oil	200 bbl per day	Jan 1, 2010 - Dec 31, 2010	85.05 per bbl	394,870
				834,307

Royalties

($Cdn.)	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Heavy oil	**654,159**	867,227	(25)	**1,826,327**	2,260,726	(19)
Light oil and NGLs	**1,162,660**	2,371,438	(51)	**3,183,271**	5,372,636	(41)
Natural gas	**(107,620)**	267,498	(140)	**289,226**	1,077,256	(73)
Total royalties	**1,709,199**	3,506,163	(51)	**5,298,824**	8,710,618	(39)
% of gross oil and gas revenue	**18%**	22%	(17)	**20%**	20%	-
Per boe	**8.93**	21.57	(59)	**8.76**	17.66	(50)

During Q3 2009, the Company paid $1,709,199 or 18% of petroleum and natural gas revenues in royalties compared to $3,506,163 or 22% in Q3 2008. Royalties paid over the nine month period for 2009 totaled $5,298,824 versus $8,710,618 when compared to the same period in 2008. The decline in royalties paid reflects the lower prices received in the current period. The royalty rate over the nine month period remained at 20% for both periods.

For 2009 to date**,** the heavy oil royalty averaged 17%, the light oil and NGL royalty rate averaged 26% and natural gas royalties averaged 7%. During the current quarter, the Company received a prior period adjustment to its gas cost allowance. As a result, the Company recovered royalties paid in prior periods and recorded a lower current period royalty rate.

On a Boe basis, royalties decreased 59% for the quarter and 50% for the nine month period due primarily to lower commodity prices and to some degree, lower production on certain wells.

In 2008, the Alberta Government announced its New Royalty Framework and subsequent thereto a number of changes and revisions to the New Royalty Framework that took effect January 1, 2009 and a Transitional Royalty Plan. It is not expected that these changes and revisions will have a major effect on the Company's royalties other than to result in some volatility in rates as commodity prices change. A Q1 2009 announcement by the Alberta Government on a "three point incentive program" to encourage additional drilling reduces royalty rates on new wells drilled to 5% for a period of one year and provides a credit of $200.00 per meter drilled. This program was later extended for an additional year. The Company is reviewing its projects and has identified some drilling locations that maximize the value of this program to the Company and will drill these projects in Q4 2009.

Operating Expenses

($Cdn.)	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Heavy oil	**1,278,562**	1,126,840	13	**3,615,606**	4,530,949	(20)
Light oil and NGLs	**1,262,224**	1,501,185	(16)	**4,422,033**	4,118,423	7
Natural gas	**672,008**	361,703	86	**2,214,082**	1,657,550	34
Total operating expenses	**3,212,794**	2,989,728	7	**10,251,721**	10,306,922	(1)
Per boe	**16.78**	18.39	(9)	**16.95**	20.90	(19)

Operating costs increased only 7% to $3,212,794 in Q3 2009 from $2,989,728 in Q3 2008. Average production for the comparable quarter increased 18%. For Q3 2009, operating costs averaged $16.78 per Boe consistent with $16.62 per Boe in Q2 2009 and down from $18.39 per Boe in Q3 2008.

For the nine month period in 2009, operating costs totaled $10,251,721 or $16.95 per Boe down 19% from the comparative 2008 figures.

Operating costs on a Boe basis are down as a result of the Company's ongoing operating cost review process, the sale or shut-in of high operating cost properties, the acquisition of GEOCAN whose operating costs on an Boe basis were lower than Arsenal's and the addition of low operating cost production in North Dakota.

Transportation Expenses

($Cdn.)	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Heavy oil	**114,023**	-	-	**355,323**	-	-
Light oil and NGLs	**42,866**	-	-	**121,524**	-	-
Natural gas	**43,010**	-	-	**156,560**	-	-
Total transportation expenses	**199,899**	-	-	**633,407**	-	-
Per boe	**1.04**	-	-	**1.05**	-	-

Transportation expenses totaled $199,899 ($1.04 per Boe) in Q3 2009 versus $222,134 ($1.09 per Boe) in Q2 2009 and $211,374 ($1.01 per Boe) in Q1 2009. These expenses include gathering, processing and transmission in British Columbia, gas service costs (firm and interruptible) in Alberta and clean oil trucking in Alberta and Saskatchewan. These costs are primarily related to the GEOCAN properties. The Company made an adjustment of processing charges to heavy oil charges originally allocated to light oil.

Operating Netback

($Cdn.)	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Heavy						
Revenue	**59.93**	98.36	(39)	**51.88**	85.65	(39)
Royalty	**10.64**	16.32	(35)	**8.74**	12.88	(32)
Operating	**20.79**	21.21	(2)	**17.30**	25.82	(33)
Transportation	**1.85**	-	-	**1.70**	-	-
Netback per barrel	**26.64**	60.82	(56)	**24.15**	46.95	(49)
Light oil and NGL's						
Revenue	**59.31**	110.34	(46)	**53.39**	106.05	(50)
Royalty	**14.74**	28.02	(47)	**14.06**	23.89	(41)
Operating	**16.00**	17.74	(10)	**19.53**	18.31	7
Transportation	**0.54**	-	-	**0.54**	-	-
Netback per barrel	**28.03**	64.64	(57)	**19.27**	63.85	(70)
Gas						
Revenue	**2.90**	8.07	(64)	**3.87**	8.76	(56)
Royalty	**(0.35)**	1.80	(120)	**0.28**	1.94	(85)
Operating	**2.20**	2.43	(10)	**2.18**	2.98	(27)
Transportation	**0.14**	-	-	**0.15**	-	-
Netback per mcf	**0.92**	3.84	(76)	**1.24**	3.84	(68)
Boe						
Revenue	**48.33**	97.00	(50)	**44.42**	88.72	(50)
Royalty	**8.93**	21.57	(59)	**8.76**	17.66	(50)
Operating	**16.78**	18.39	(9)	**16.95**	20.90	(19)
Transportation	**1.04**	-	-	**1.05**	-	-
Netback per Boe	**21.58**	57.04	(62)	**17.66**	50.15	(65)

The operating netback (before commodity price contracts) for Q3 2009 was $21.58 up slightly from $20.84 per Boe in Q2 2009 and from $10.99 for Q1 2009 but down 62% from $57.04 per Boe for Q3 2008. This fluctuation in the commodity netback between periods is primarily the result of fluctuating commodity prices over the comparative periods.

Increased oil and to a lesser degree natural gas prices, lower operating costs, due to high operating cost heavy oil property sales, and operational efficiencies were responsible for the increased netback in Q3 2009 and Q2 2009 over Q1 2009. On an individual product basis, the net back for heavy oil declined 56% during the current quarter to $26.64 per barrel versus $60.82 per barrel for Q3 2008. The decline is due to lower prices received during the current quarter versus the comparative quarter. Average light crude and NGL netback was $28.03 per barrel for the current quarter versus $64.64 per barrel in the comparable quarter in 2008. For natural gas the Q3 2009 netback was $0.92 per Mcf versus $1.22 per Mcf in Q2 2009, $ 1.81 per Mcf for Q1 2009 and $3.84 per mcf for Q3 2008. The decline in the company's netback for natural gas reflects the price deterioration of the commodity over the past year.

General and Administrative Expenses

($Cdn.)	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Gross expenditures	**1,157,821**	1,662,864	(30)	**3,576,598**	3,710,292	(4)
Overhead recovery	**(127,612)**	(151,918)	(16)	**(325,455)**	(357,610)	(9)
Capitalized overhead	**(87,900)**	(85,000)	3	**(263,700)**	(200,000)	32
Net general and administrative expense	**942,309**	1,425,946	(34)	**2,987,443**	3,152,682	(5)
Net general and administrative per boe	**4.92**	8.77	(44)	**4.94**	6.39	(23)

For Q3 2009, gross general and administrative expenditures decreased 30% to total $1,157,821 when compared to $1,662,864 for Q3 2008. On a net basis, costs were also lower totaling $942,309 for the current quarter versus $1,425,946 for Q3 2008.

For the current nine month period, gross general and administrative expenditures decreased 4% to total $3,579,598 when compared to $3,710,292 for the nine month period ending in 2008. On a net basis, general and administrative expenses totaled $2,987,443 for 2009 versus $3,152,682 for 2008, a decrease of 5%.

On a Boe basis, current quarter general and administrative expenses were $4.92 per Boe versus $8.77 in Q3 2008 and on a year to date basis, costs were down 23% to $4.94 per Boe in 2009 versus $6.39 per Boe in 2008.

In 2009, the Company has accrued costs relating to the conversion to International Financial Reporting Standards, the conversion and upgrade of its accounting system and incurred additional consulting and legal fees relating to the integration of GEOCAN. In addition, as a result of its move into the larger GEOCAN office space in Q4 2008, the Company has paid higher costs associated with its office rent and has incurred increases in its annual and quarterly reporting fees due to its larger shareholder base. The Company has sublet a portion of its office space for 2010 which will result in reduce occupancy costs for 2010 and for the remaining term of its lease.

Overhead recovery decreased in the current quarter to $127,612 from $151,918 in Q3 2008. On a year to date basis, the overhead recovery has decreased 9% due to the decline in Company operated projects. Overhead from operations increased due to the number of operated wells while overhead related to capital expenditures decreased due to the Company not operating any wells or major capital projects during the first nine months of 2009. The Company participated in the drilling of three wells in North Dakota, but did not operate any of the wells. The Company expects to operate at least three wells in Q4 2009 and will therefore recognize higher overhead recoveries.

The Company capitalizes overhead directly related to exploration and development activities. For Q3 2009, the Company's capitalized overhead, excluding stock based compensation, was $87,900 versus $85,000 in Q3 2008. For 2009 year to date, capitalized direct overhead increased 32% due to the addition of a geologist in Q3 2008.

Finance Charges and Fees

($Cdn.)	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Financing charges and fees	**409,864**	80,216	411	**1,174,677**	341,779	244
Per boe	**2.14**	0.49	334	**1.94**	0.69	180

Financing charges include interest and fees paid on the Company's credit facility, interest paid on the Company's unspent flow-through share obligation and other interest charges. Financing charges and fees increased to $409,864 for Q3 2009 ($80,216 for Q3 2008) primarily due to a higher average borrowing base and to $1,174,677 for the year to date period ($341,779 for year to date 2008), primarily as a result of increased fees paid on the Company's renewed credit facility (paid in Q2 2009), the higher average balance outstanding during the period (due to redemption of the convertible debenture in February 2009 and the acquisition of GEOCAN) offset by an Q1 2009 refund of interest paid on prior years flow-through share obligations.

Interest on the Company's revolving reducing term loan facility is at rates ranging from Canadian or US prime plus 1.25% to 2.25% on prime based loans, from the base rate plus 2.75% to 3.75% on guaranteed notes and from the Libor base rate plus 2.75% to 3.75% on Libor based loans. Interest on the Company's non-revolving reducing term loan facility is at Canadian or US prime plus 3.00% on prime based loans and from the base rate plus 4.75% on guaranteed notes and Libor based loans. Borrowings of guaranteed notes and Libor loans are limited under the non-revolving reducing term loan facility to 60% of the outstanding balance.

The interest rate is set based on the net debt to trailing funds flow (funds flow for the last quarter annualized) ratio. Based on the current quarter calculation, the Company will remain at the higher end of the interest rate grid.

Average borrowing under the facility for the current quarter was approximately $33.4 million versus approximately $34.9 million during Q2 2009, $40.5 million during Q1 2009 and $6.0 million for the comparative quarter in 2008. The reduction in the average borrowing under the facility during the quarter was from the application to debt of the proceeds of the FTS offering, excess funds from operations and the proceeds of the property sale. The GEOCAN acquisition accounted for the increase in the credit facility quarter over quarter.

Other Expense

($Cdn.)	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Other expense	**10,000**	-	-	**600,000**	438,056	37
Per boe	**0.05**	-	-	**0.99**	0.89	12

Other expense represents an assessment by Canada Revenue Agency ("CRA") of a tax return for a company acquired by Arsenal in 2006. The Q2 2009 assessment of $590,000 relates to a period, prior to the acquisition of the company, and involves the disallowance of ARTC and includes penalty and interest. The Company has filed a Notice of Objection with CRA, disputing the basis of the assessment. The outcome of the objection is indeterminable and a provision for the entire amount of the assessment has been made. In Q3 2009, the Company accrued additional interest on the assessment of $10,000.

In Q2 2008, the Company recorded a total of $438,056 of other expenses that included $213,056 of pre acquisition costs incurred in 2008 related to a corporate acquisition and costs to abandon wells not previously provided for in the Company's asset retirement obligation account and $225,000 related to a loan to a former officer and director that was forgiven in Q2 2008.

Interest on Convertible Debentures

($Cdn.)	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Interest on debentures	-	70,172	(100)	**34,323**	208,611	(84)
Per boe	-	0.43	(100)	**0.06**	0.42	(87)

The Company paid interest semi-annually on June 30 and December 31 at 8% per annum on the $3,480,000 of convertible debentures acquired in a prior acquisition.

In Q1 2009, the Company paid $34,323 of interest on the debentures and recorded $16,911 of accretion expense relating to the amortization of the discount on the debentures. The debentures were redeemed on February 15, 2009.

Depletion Depreciation and Accretion

($Cdn.)	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Depletion, depreciation and accretion	**5,909,734**	4,052,324	46	**19,234,834**	11,447,483	68
Per boe	**30.87**	24.93	24	**31.81**	23.21	37

Depletion, depreciation and accretion for the current quarter totaled $5,909,734 an increase of 46% from $4,052,324 for Q3 2008. For the nine month period, depletion, depreciation and accretion increased 68% to $19,234,834 for the 2009 period. The 46% increase from Q3 2008 results partially from an 18% increase in production over the comparative periods and the 68% increase on a year to date basis results partially from a 23% increase in production in Q2 2008. In addition, higher depletion, depreciation and accretion costs were recorded due to the GEOCAN acquisition and higher finding costs.

On a Boe basis the rate increased 24% in Q3 2009 to $30.87 per Boe versus $24.93 per Boe for Q3 2008 and to $31.81 per Boe for the nine month period up from $23.21 for the prior comparative period. The increase per Boe results primarily from higher industry finding and development costs during 2008 and early 2009, from property sales during the periods and from the acquisition of GEOCAN. Based on the purchase price allocation of approximately $60.4 million to property plant and equipment and proved reserves of 1.7 million Boe, the depletion and depreciation rate for the GEOCAN purchase is $35.53 per Boe. The Company expects to convert some of the GEOCAN probable reserves to proven once prices recover and drilling restarts.

Stock-based Compensation Expense

($Cdn.)	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Stock-based compensation expense	**211,488**	235,757	(10)	**750,047**	537,733	39

The Company accounts for its stock-based compensation program using the fair-value method. Under this method, compensation expense related to this program is recorded in the statement of loss over the vesting period of the options.

In 2009, the Company granted 1,788,000 options at a weighted average price of $0.21 per share to directors, officers and employees. These options vest annually over three years and expire five years from date of grant.

Stock-based compensation expense for Q3 2009 decreased 10% to $211,488 and for the year to date, increased 39% to $750,047. The increase in the 2009 year to date period, results from the timing and valuation of options issued in 2008 and in Q1 of 2009.

During the first nine months of 2009 the Company capitalized to property plant and equipment $164,158 of stock based compensation representing stock based compensation relating to exploration overhead capitalized.

Income Taxes

For the nine month period ended September 30, 2009, the Company recorded a net reduction in income taxes of $3,197,311 consisting of a current income tax provision relating to the US operations of $277,621 and a future income tax reduction of $3,474,932 relating to Canadian operations. Low average commodity prices and higher depletion and depreciation charges in the quarter were primarily responsible for the loss before income taxes and the resultant reduction of future income taxes.

At September 30, 2009, $222,145 has been recorded as a current future income tax liability and relates to the current portion of the unrealized risk management contract recorded in the financial statements. A future income tax liability of $10,124,069 has been recorded as at September 30, 2009.

Arsenal does not expect to pay current tax in Canada during 2009 based on existing tax pools available to offset realized commodity contract gains, planned expenditures and current commodity prices.

In the US, due to the realization of a significant gain on the monetizing of a commodity contract and due to increasing production and prices, the Company may be taxable in 2009 depending on the level of spending during the remainder of the year. Efforts are underway to minimize the tax impact on the Company's operations.

Cash and Funds From Operations and Net Income (Loss)

	Three Months Ended September 30			Nine Months Ended September 30		
($Cdn.)	**2009**	2008	Change	**2009**	2008	Change
Cash provided by operating activities	**3,114,799**	9,133,964	(66)	**14,089,419**	18,591,708	(24)
Funds from operations	**2,887,826**	8,093,157	(64)	**15,234,818**	19,974,306	(24)
Per share						
Basic	**0.03**	0.09	(69)	**0.15**	0.23	(34)
Diluted	**0.03**	0.09	(69)	**0.15**	0.23	(34)
Net income (loss)	**(1,897,761)**	10,028,193	120	**(8,205,132)**	7,614,314	209
Per share						
Basic	**(0.02)**	0.11	117	**(0.08)**	0.09	194
Diluted	**(0.02)**	0.11	117	**(0.08)**	0.09	194

Q3 2009 funds from operations totaled $2,887,826 ($0.03 per share basic and diluted) down from $8,093,159 ($0.09 per share basic and diluted share) in Q3 2008. This decrease is attributed to lower commodity prices that offset increased production and lower operating costs.

For the current nine month period, funds from operations totaled $15,234,818 ($0.15 per share basic and diluted) down from $19,974,306 ($0.23 per share basic and diluted) in the comparable 2008 period. This decrease is attributed to lower average 2009 commodity prices offset by an increased in the period to date funds received in 2009 from the settlement of commodity contracts versus 2008 and higher average production. The effect of the 23% production increase was more than offset by the 50% decrease in average commodity prices received.

The net loss for Q3 2009 of $1,897,761 ($0.02 per share basic and diluted) showed improvement when compared to the Q2 2009 loss of $3,235,660 ($0.02 per share basic and diluted) but significantly reduced from the comparable quarter that recorded income of $8,093,157 ($0.09 per share basic and diluted) recorded in Q2 2008. On a year to date basis, the 2009 loss totaled $8,205,132 or $0.08 per share basic and diluted versus income of $7,614,314 or $0.09 per share basic and diluted for the comparative nine month period. The increased loss for the respective periods is attributed to lower average commodity prices during the current periods and higher per unit depletion and depreciation charges.

OUTLOOK

During the third quarter, the Company completed and put on production two additional Bakken wells at Stanley and completed the drilling of a Three Forks well at Stanley. Subsequent to quarter end the Three Forks well was put on production.

Funds from operations for Q4 2009 (excluding realized financial contract gains or losses) are expected to be approximately $4.0 million. This projection is based on an expected Q4 2009 average production rate of approximately 2,175 and a 2009 exit rate of approximately 2,350 Boe per day resulting in average production for 2009 of between approximately 2,200 Boe and 2,300 Boe per day and utilizes the current 2009 WTI strip price of approximately $80.00 US per barrel and a Canadian US exchange rate of $0.94. Arsenal's expected 2009 mix of oil (75%) and natural gas (25%) is expected to generate revenue of approximately $58.75 per Boe for Q4 2009 before any adjustments to revenue for commodity contracts.

Capital expenditures for Q4 2009 are expected to total approximately $3.1 million (all in Canada) allocated to a small acquisition, drilling at Evi in Alberta, various recompletions and to putting on behind pipe production. The Company expects to sell additional non-core properties during the fourth quarter. Year end net debt (see Credit Facility) is expected to be reduced from the current level of $33.3 million to between $28.0 and $30.0 million at 2009 year end.

In 2010, should the current crude oil prices remain around current levels, the Company expects to participate in drilling Bakken and Three Forks wells in North Dakota and to drill in Canada at Evi, Wildmere and Galahad to take advantage of the drilling credits and reduced royalty rates in Alberta. The Company expects to participate in approximately 24 gross wells of which seven are expected to be drilled in North Dakota at Stanley or Lindahl. The Company's Board of Directors has approved a total capital budget of $30.5 million. Based on current plans and expected timing, the Company is expected to average between 2,600 and 2,800 Boe per day and generate cash from operations of from between $27.0 and $28.0 million. Net debt at year end 2010 is estimated to be between $30.0 and $32.0 million. The Company's 2010 budget utilizes the current 2010 WTI strip price of approximately $84.00 US per barrel and a Canadian/US exchange rate of $0.95. Arsenal's expected 2010 mix of oil (76%) and natural gas (24%) is expected to generate revenue of approximately $63.00 Cdn. per Boe for 2010 before any adjustments for commodity contracts.

Summary of Quarterly Results

($Cdn.)	**2009**			2008				2007
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Oil and gas revenue	**9,252,597**	9,638,098	7,969,913	10,724,915	15,766,815	16,678,644	11,309,151	8,827,883
Net income (loss)	**(1,897,761)**	(3,235,660)	(3,071,711)	6,974,803	10,028,193	(1,925,853)	(488,026)	(2,944,193)
Per share - basic	**(0.02)**	(0.03)	(0.03)	0.08	0.11	(0.02)	(0.01)	(0.04)
Per share - diluted	**(0.02)**	(0.03)	(0.03)	0.08	0.11	(0.02)	(0.01)	(0.04)
Funds from operations	**2,887,826**	2,031,722	10,315,270	11,316,461	8,093,159	8,083,001	3,798,146	134,648
Per share - basic	**0.03**	0.02	0.10	0.13	0.09	0.09	0.05	-
Per share - diluted	**0.03**	0.02	0.10	0.13	0.09	0.09	0.05	-
Total assets	**118,244,383**	122,486,146	131,477,316	143,723,628	78,546,339	72,989,632	71,113,137	65,097,402
Total debt(1)	**33,285,548**	37,104,499	40,124,195	48,479,097	13,384,766	14,266,267	18,709,928	20,731,800
Shares outstanding	**109,961,890**	101,249,646	101,249,646	101,249,646	90,786,148	90,719,815	89,181,542	83,698,042

(1) Includes working capital and convertible debentures outstanding but excludes risk management contracts and future income taxes whether current or long term assets or liabilities.

Arsenal's quarterly results have fluctuated significantly in the past eight quarters due to the GEOCAN acquisition, production increases, some significant unusual items such as tax audits being recorded and then reversed, ceiling test write-downs and the recognition of impairment of properties. More recently, commodity prices have been very volatile and have been responsible for wide swings in revenues and realized and unrealized gains and losses thus impacting operating income. For Arsenal, quarterly results will continue to fluctuate somewhat and will depend on property dispositions, the movement in commodity prices particularly for oil and the differentials in heavy oil and the drilling program in North Dakota and in Canada. Given a more stable commodity market and the establishment and maintenance of a core property base coupled with the recent implementation of various operational efficiencies and continued drilling success in North Dakota, the Company expects its established production base to increase steadily and lead to more comparative and stable results going forward.

Contractual Obligations

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

- purchase of services
- royalty agreements
- operating agreements
- processing and treating agreements
- right-of-way and road use agreements
- lease obligations for office space and equipment
- flow-through share agreements

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

Obligations with a fixed term are as follows:

($Cdn.)	**2009**	2010	2011	2012
Lease of office premises	**160,729**	392,179	338,602	197,518
Equipment lease	**5,206**	19,086	-	-
Total	**165,935**	411,265	338,602	197,518

The Company entered into a sublease with a term commencing February 1, 2010 and ending July 30, 2012 that has reduced its future office lease commitment.

Summary of Results by Country

Nine Months Ended September 30, 2009	Canada	United States	**Total Company**
Revenue			
Oil and gas	20,152,263	6,708,345	**26,860,608**
Gain (loss) on risk management contracts	(144,830)	1,123,454	**978,624**
Royalties	(3,164,973)	(2,133,851)	**(5,298,824)**
	16,842,460	5,697,948	**22,540,408**
Other income	28,750	2,202	**30,952**
	16,871,210	5,700,150	**22,571,360**
Expenses			
Operating	8,111,118	2,140,603	**10,251,721**
Transportation	633,407	-	**633,407**
General and administrative	2,296,787	690,656	**2,987,443**
Finance charges and fees	1,029,997	144,680	**1,174,677**
Other expenses	600,000	-	**600,000**
Interest on convertible debentures	34,323	-	**34,323**
Foreign exchange gain	(1,442,588)	(266,972)	**(1,709,560)**
Convertible debenture accretion	16,911	-	**16,911**
Depletion, depreciation, and accretion	18,039,868	1,194,966	**19,234,834**
Stock-based compensation	750,047	-	**750,047**
	30,069,870	3,903,933	**33,973,803**
Income (loss) before income taxes	(13,198,660)	1,796,217	**(11,402,443)**

Bank Debt, Liquidity and Capital Resources

Capital Management

In order to continue the Company's ongoing exploration and development program, the Company must maintain a strong capital base. A strong capital base results in increased market confidence, an essential factor in maintaining existing shareholders and in attracting new investors. The Company is committed to establishing and maintaining a strong capital base to ensure the Company has access to the equity and debt markets when deemed advisable. In order to maintain a strong capital base, the Company continually monitors the risk reward profile of its exploration and development projects 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.

The Company considers shareholders equity, bank debt and working capital as components of its capital base. Arsenal's convertible debentures were redeemed in February 2009 funded by an increase in bank debt. The Company can access or increase capital through the issuance of shares, through bank borrowings that are based on reserves, and by building cash reserves by reducing its capital expenditure program.

The Company monitors its capital based primarily on its debt to annualized funds flow ratio and its debt to equity ratios. Debt includes bank debt, plus or minus working capital. Annualized funds flow is calculated as cash flow from operations before changes in non-cash working capital and asset retirement expenditures from the Company's most recent quarter multiplied by four adjusted, by increasing or decreasing commodity price expectations. The Company's goal is to target this ratio at 1 : 1 but it can and will fluctuate based on the timing of property transactions, commodity prices and on the mix of exploratory and development drilling. During periods of extreme commodity price declines, high drilling activity or after large property or corporate acquisitions, it is expected that the ratio would increase and during periods of high commodity prices and low activity levels, the ratio would decrease. The Company's focus in these instances is to concentrate on bringing the ratio back into line. The Company prepares an annual operating and capital expenditure budget. The budget is updated when critical factors change and actual results are realized. Critical factors include economic factors such as the state of equity markets, changes to commodity prices, interest rates and foreign exchange rates and non economic factors such as drilling results and production profiles. The Company's board of directors approves the budget and reviews changes thereto.

At September 30, 2009, the Company's debt (excluding the Company's risk management contracts and current future income taxes whether assets or liabilities) to funds flow (Q3 2009 annualized) was 2.88 : 1 and its debt to equity ratio was 0.60 : 1. The debt to forward funds from operations ratio at September 30, 2009 is higher that the corporate goal of 1 : 1 as established in the management strategy goals and guidelines. The Company acquired GEOCAN at close to the peak of the last commodity price cycle and, because the Company was under levered at the time, used primarily debt to complete the acquisition. Since the acquisition, there was a significant deterioration of commodity prices which have recovered somewhat recently. This price decline has resulted in much lower future cash flows resulting in an increase in the debt to forward funds flow ratio. As prices increase and firm, management believes that the current ratio, while high is manageable and will be reduced through prudent fiscal management of cash in-flows and capital expenditures. A flow through share equity issue in Q3 2009 initially helped with debt reduction and further issues may be considered. The Company expects to continue to participate in its Bakken drilling at Stanley, North Dakota utilizing a portion of funds generated from future cash flows and will continue to dedicate the remaining future cash flows and the proceeds from non-core property sales to debt reduction. Key factors that will determine when the Company will be within its established guidelines are increased production, commodity (particularly crude) prices and the magnitude of capital requirements to continue participation in the Bakken North Dakota drilling. The Company is continuing with its commodity risk management program to lock-in a portion of future funds from operations and has nominated a portion of its debt in US dollars as an economic hedge against the foreign exchange fluctuations affecting certain elements of its business.

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

> the working capital ratio (as defined in the agreement to include the unutilized portion of the facility) to fall to below 1 : 1.

At September 30, 2009, the Company is in compliance with this covenant.

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

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

Credit Facility

At September 30, 2009, the Company had a $37.54 million credit facility consisting of a demand revolving operating loan facility in the amount of $31.0 million and a non-revolving reducing term loan facility in the amount of $6.54 million. The facility can be utilized in either Canadian or US dollars. Reductions in the non-revolving reducing term loan facility are set at $820,000 per month and the facility is expected to be repaid no later than May 31, 2010. Debt under the facility, that includes bank debt and working capital but excludes the risk

management contracts and related future income tax amounted to $33.3 million at September 30, 2009. Included in debt under the facility is U.S. $10,000,000 (CAD - $10,707,000) Libor based loan.
Interest on the Company's revolving reducing term loan facility is at rates ranging from Canadian or US prime plus 1.25% to 2.25% on prime based loans, from the base rate plus 2.75% to 3.75% on guaranteed notes and from the Libor base rate plus 2.75% to 3.75% on Libor based loans. Interest on the Company's non-revolving reducing term loan facility is at Canadian or US prime plus 3.00% on prime based loans and from the base rate plus 4.75% on guaranteed notes and Libor based loans. Borrowings of guaranteed notes and Libor loans are limited under the non-revolving reducing term loan facility to 60% of the outstanding balance.

The interest rate is set based on the net debt to trailing funds flow ratio (funds flow for the last quarter annualized). Based on the current net debt to annualized funds flow ratio, the interest rate will be at the top of the interest rate grid. The Company is working to reduce this ratio and thereby reduce borrowing costs.

The credit facility is secured by a fixed and floating charge debenture providing a fixed charge over all present and after acquired petroleum and natural gas interests and a floating charge over all lands, a continuing guarantee from the Company's US subsidiary in the form of a Mortgage Security Agreement and Letter of Undertaking limited to $13,000,000.

The Company is in compliance with its bank covenants at September 30, 2009.

Liquidity

The sudden and severe decline in commodity prices that commenced in Q4 2008 and lasted until the end of Q1 2009, the limited access to equity markets and the Company's high debt load affected management's approach and operating strategy in 2009. As a result of these factors, the Company was focused on reducing operating costs and capital expenditures (except expenditures on the Company's Bakken play in North Dakota to preserve its interest in the lands) selling non-core properties, paying down its debt and weathering the economic storm. It appears that, as a result of the apparent economic recovery, crude prices have improved and stabilized. This has led to an improvement in the Company's funds from operations and its access to capital. In September 2009, the Company issued 8,750,000 flow-through shares at $0.40 per share for gross proceeds of $3,500,000. The proceeds were used to reduce debt. The Company is committed to incurring $3,500,000 of qualifying expenditures by December 31, 2010. The Company will continue to take a cautious financial approach and remains focused on debt reduction with a portion of cash flow and equity dedicated to capital programs to increase production.

The Company believes it has the financial resources necessary to both reduce debt to an acceptable level and to complete its 2009 proposed capital program. In the event that commodity prices, interest or exchange rates, or other factors negatively impact funds flow from operations, the Company would plan to reduce the remaining 2009 capital program so that the Company's debt stays within its expected credit facility and that the Company is able to meet its financial obligations.

In order to ensure that funds were available for the Company's 2009 and 2010 capital program, the Company has in-place certain commodity hedges. At September 30, 2009 the Company had the following commodity contracts in-place:

($Cdn.)

Commodity Sold	Notional Volume	Remaining Term	Pricing	Fair Value
Natural Gas	1,000 GJ per day	Jan 1, 2010 - Dec 31, 2010	6.78 per GJ	375,317
Natural Gas	1,000 GJ per day	Nov 1, 2009 - Mar 31, 2010	5.50 per GJ	11,699
Oil	100 bbl per day	Oct 1, 2009 - Apr 30, 2010	72.60 per bbl	(93,310)
Oil	100 bbl per day	May 1, 2010 - Apr 30, 2011	79.50 per bbl	(55,821)
Oil	400 bbl per day	Oct 1, 2009 - Dec 31, 2009	81.50 per bbl	201,552
Oil	200 bbl per day	Jan 1, 2010 - Dec 31, 2010	85.05 per bbl	394,870
				834,307

Commodity contracts may be monetized or additional commodity contracts may be put in-place, depending on changes in commodity prices and the expected level of the Company's capital expenditure program.

Share Capital

In September 2009, the Company issued 8,750,000 flow-through shares at $0.40 per share for gross proceeds of $3,500,000. In July, the Company cancelled (under the terms of a sunset clause) 37,756 common shares issued pursuant to a corporate transaction.

In January 2009, the Company issued 1,688,000 options at $0.21 to directors, officers and employees. In August the Company granted 100,000 options at $0.36 per share to a new employee. In October 2009, the Company granted 150,000 options at $0.45 per share to another new employee and had 150,000 options expire. To date in 2009, the Company has had 1,172,000 (372,000 during Q3 2009 and 150,000 subsequent to quarter end) options expired unexercised.

At September 30, 2009 and as of the date of this MD&A, the Company has 109,961,890 common shares and 8,127,000 options outstanding.

	Nine Months Ended September		Year Ended December 31	
Common shares		**2009**		2008
	Shares	**Amount ($)**	Shares	Amount ($)
Balance - beginning of period	**101,249,646**	**93,515,925**	83,698,042	81,901,603
Issued to acquire Geocan	**-**	**-**	10,623,498	8,445,681
Issued on exercise of options	**-**	**-**	283,251	90,217
Allocated from contributed surplus	**-**	**-**	-	60,490
Private placement of common shares	**-**	**-**	1,249,300	787,059
Private placement of flow-through shares	**8,750,000**	**3,500,000**	5,555,555	4,000,000
Tax effect of flow-through shares	**-**	**(1,040,000)**	-	(1,356,625)
Share issue costs	**-**	**(247,890)**	-	(392,062)
Tax effect of share issue costs	**-**	**66,475**	-	127,425
Unclaimed shares returned to treasury	**(37,756)**	**(34,484)**	-	-
Normal course issuer bid	**-**	**-**	(160,000) -	147,863
Balance - end of period	**109,961,890**	**95,760,026**	101,249,646	93,515,925

In October 2008, the Company announced approval to purchase up to 4,539,307 of its common shares by way of a normal course issuer bid (NCIB) through the facilities of the Toronto Stock Exchange. The bid expired on October 15, 2009. No shares were purchased under the bid in 2009. The Company had purchased and cancelled 160,000 at an average price of $0.195 per share in 2008.

In March 2009, the board of directors adopted a shareholder rights plan which is designed to ensure fair treatment of the Company's shareholders by providing shareholders more time than is afforded under existing Canadian legislation to properly evaluate any unsolicited takeover bid and to seek possible alternatives to maximize value for all shareholders. The Company is not aware of any pending or contemplated takeover bids.

Related Party Transactions

A director of the Company is a partner in a law firm that periodically provides legal services to the Company. During the first nine months of 2009, the Company recorded a total of $1,547 (2008 - $nil) for legal fees and disbursements.

An officer of the Company is a partner in a law firm that provides legal services to the Company. During the first nine months of 2009, the Company recorded a total of $118,902 (2008 - $334,002) for legal fees and disbursements.

All related party transactions occur in the normal course of operations and have been recorded at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Capital Expenditures

($ Cdn.)	Three Months Ended March 31 2009	Three Months Ended June 30 2009	Three Months Ended September 30 2009	Year to Date 2009
Land	348,298	(54,996)	284,623	577,925
Seismic	29,157	79,130	16,570	124,857
Drilling and completions	1,748,748	815,529	2,594,495	5,158,772
Capitalized general and administrative	87,900	87,900	87,900	263,700
Production equipment, facilities and tie-ins	360,958	207,882	279,711	848,551
Other	102,647	48,294	80,082	231,023
Total property plant and equipment additions	2,677,708	1,183,739	3,343,381	7,204,828
Non-cash additions	(102,647)	(43,894)	(78,414)	(224,955)
Capital expenditures	2,575,061	1,139,845	3,264,967	6,979,873
Property dispositions	(839,375)	(2,326,749)	(265,860)	(3,431,984)

During the quarter, the Company disposed of its interest in the Worsley area, a minor property for proceeds of $265,860 bringing the year to date total to $3,431,984 million. Production from all properties sold totaled less than 100 Boe per day. In addition to proceeds received on the sale of these properties, the Company reduced its asset retirement obligations by $2,330,981.

During Q3 2009, the Company completed drilling two Bakken and one Three Forks well in North Dakota. The two Bakken wells went on production during the quarter and the Three Forks well was completed after quarter end. To date in Q3 2009, the Company has participated in the drilling of 5 gross, 1.01 net wells, all non-operated and all in North Dakota. Four of the wells have targeted the Bakken with one targeting the Three Forks. Additional Bakken and Three Forks wells are expected either during Q4 2009 or Q1 2010.

Capital expenditures for Q3 2009 totaled $3,264,967lower than in the comparative 2008 quarter during which the Company spent $7,432,914. Expenditures have been reduced in response lower commodity prices and restricted capital and credit availability. To date in 2009, the Company has spent $6,979,873 ($17,110,739 to Q3 2008) on the drilling of the North Dakota wells and recompleting wells in BC.

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, is 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.

Risk Factors

Commodity price risk

Commodity price risk is defined as fluctuations in crude oil, natural gas, and natural gas liquid prices. The Company uses derivative instruments as part of its risk management approach to manage commodity price fluctuations and stabilize funds from operations available for future development programs. The Company does not enter into derivative contracts for speculative purposes. During 2008, the Company entered into four crude oil derivative contracts and one natural gas derivative contract. These contracts were monetized during late 2008 and Q1 2009.

See "Liquidity" for the Company's current commodity contracts.

Production risk

Production risk relates to the Company's ability to produce, process and transport crude oil and natural gas. To manage this risk to an acceptable level, the Company performs regular and proactive maintenance on its wells, facilities and pipelines. The Company operates approximately 80% of its production, which affords greater control over operations. Approximately 20% of the Company's production is in the United States.

Natural Decline and Reserve Replacement Risk

Natural decline risk relates to the Company's ability to replace reserves in excess of annual production declines through development activities such as drilling, well completions, well workovers and other capital activities. The Company manages its business using a portfolio approach whereby capital is allocated across a number of areas so that significant capital is not risked on any one activity. Capital is spent only after strict economic criteria for production and reserve additions are assessed.

The Company's reserves are evaluated on an annual basis by independent third-party consultants reporting to the Company's Reserves Committee of the Board of Directors. The Company's approach is to invest in mature, long-life properties with a high proved producing component combined with low-risk development opportunities where the reserve risk is generally lower and cash flows are more stable and predictable. The Company will engage in wildcat exploration activities only after considerable due diligence has been completed on the play, including geological, geophysical and total capital required.

Environmental Health and Safety Risk

Environment, health and safety risks relate primarily to field operations associated with oil and gas assets. To mitigate this risk, a preventative environmental, health and safety program is in place as well as operational loss insurance coverage. Arsenal employees and contractors adhere to the Company's environment, health and safety program, which is routinely reviewed and updated to ensure that the Company operates in a manner consistent with best practices in the industry. The Board of Directors is actively involved in the risk assessment and risk mitigation process.

Regulation, Tax and Royalty Risk

Regulation, tax and royalty risk relates to changing government royalty regulations, income tax laws and incentive programs impacting the Company's financial and operating results. Management, with the assistance of legal and accounting professionals, stay informed of proposed changes in laws and regulations and proactively responds to and plan for the effects of these changes.

Capital Market Risk

The Company's ability to maintain its financial strength and liquidity is dependent upon its ability to access Canadian capital markets. If Canadian debt or equity markets were to become less accessible to the Company, it may affect the ability of Arsenal to continue to replace production.

Change in Accounting Policies

Accounting Changes

Translation of foreign currencies

Effective April 1, 2009, the Company determined that the functional currency of its U.S. operations had changed from the Canadian dollar to the U.S. dollar due to significant changes in facts and circumstances, being the recent financing for and cash flow generated from U.S. operations being denominated in U.S. dollars and being self-sustaining from that of the Company (parent). Accordingly, the accounts of self-sustaining foreign operations are translated using the current rate method commencing April 1, 2009, whereby assets and liabilities are translated at period-end exchange rates, while revenues and expenses are translated using average rates for the period. Translation gains and losses related to the operations are included in other comprehensive income and included in accumulated other comprehensive income as a separate component of shareholders' equity. Previously, U.S. operations were considered to be integrated and translated using the temporal method. Under the temporal method, monetary assets and liabilities were translated at the period end exchange rates, other assets and liabilities at the historical rates and revenues and expenses were translated at exchanges rates in the period they occurred. This change was applied prospectively beginning April 1, 2009.

Goodwill and intangible assets

New standards for Goodwill and Intangible Assets effective for fiscal years beginning on or after October 1, 2008, provide guidance on the recognition, measurement, presentation and disclosure for goodwill and intangible assets, other than the initial recognition of goodwill or intangible assets acquired in a business combination. Retroactive application to prior-period financial statements will be required. The Company is still assessing the impact of this new standard on its financial statements. The adoption of this standard has had no impact on the Company's Consolidated Financial Statements.

Future Accounting Changes

Business combinations

New standards for Business Combinations and related standards for non-controlling interests and consolidated financial statements are effective January 1, 2011 and apply prospectively to business combinations for which the acquisition date is on or after the first annual reporting period beginning on or after January 1, 2011 for the Company. Early adoption is permitted. These standards harmonize the Canadian standards with IFRS.

Financial Instruments

In May 2009, the Canadian Institute of Chartered Accountants amended Section 3862, “Financial Instruments – Disclosures,” to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These amendments are effective for the Company on December 31, 2009

International Financial Reporting Standards (“IFRS”)

In February 2008, the CICA Accounting Standards Board (“AcSB”) confirmed the changeover to IFRS from Canadian GAAP will be required for publicly accountable enterprises interim and annual financial statements effective for fiscal years beginning on or after January 1, 2011. The eventual changeover to IFRS represents a change due to new accounting standards. The transition from current Canadian GAAP to IFRS is a significant undertaking that may materially affect the Company's reported financial position and results of operations.

The International Accounting Standards Board (“IASB”) has approved amendments and exemptions to IFRS 1 in order to make it more useful to Canadian entities adopting IFRS for the first time. One such exemption relating to full cost oil and gas accounting reduces the administrative burden in the transition from the current Canadian Accounting Guideline 16 (related to the full cost method of accounting for oil and gas activities) to IFRS. The amendment will permit the Company to apply IFRS prospectively to their full cost pool, rather than the retrospective assessment of capitalized exploration and development expenses, with the provision that an impairment test, under IFRS standards, be conducted at the transition date.

Although the Company has not completed development of its IFRS changeover plan, when finalized it will include project structure and governance, resourcing and training, an analysis of key GAAP differences and a phased plan to assess accounting policies under IFRS as well as potential IFRS 1 exemptions. The Company anticipates completing its project scoping, which will include a timetable for assessing the impact on data systems, internal controls over financial reporting, and business activities, such as financing and compensation arrangements, during 2009.

Disclosure Controls and Procedures

The Company has established disclosure controls and procedures for the timely and accurate preparation of financial and other reports. Disclosure controls and procedures are designed to provide reasonable assurance that material information required to be disclosed is recorded, processed, summarized and reported within the periods specified by applicable securities regulations and that information required to be disclosed is accumulated and communicated to the appropriate members of management and properly reflected in the Company’s filings. Consistent with the concept of reasonable assurance, the Company recognizes that the relative cost of maintaining these disclosure controls and procedures should not exceed their expected benefits. As such, the Company’s disclosure controls and procedures can only provide reasonable assurance, and not absolute assurance, that the objectives of such controls and procedures are met. The Chief Executive Officer and the Chief Financial Officer oversee this evaluation process and have concluded that the design and operation of these disclosure controls and procedures are not effective in providing reasonable assurance that material information required to be disclosed by the Company in reports filed with Canadian securities regulators is accurate and complete and filed within the periods required due to the material weaknesses identified in internal controls over financial reporting as noted below. The Chief Executive Officer and the Chief Financial Officer have individually signed certifications to this effect. There were no changes during the first nine months of 2009 in disclosure controls and procedures.

Internal Controls over Financial Reporting

The Chief Executive Officer and Chief Financial Officer of Arsenal are responsible for designing and ensuring the operating effectiveness of internal controls over financial reporting or causing them to be designed and operating effectively under their 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 Canadian GAAP. Arsenal's management has assessed the design and operating 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 and operating effectiveness 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 during the first nine months of 2009 to material weaknesses in internal controls over financial reporting.