



# **Management's Discussion and Analysis ("MD&A")**

**September 30, 2009**

**Dated November 6, 2009**

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# EPSILON ENERGY LTD.

## MANAGEMENT'S DISCUSSION AND ANALYSIS

### Overview

This Management's Discussion and Analysis ("MD&A") is intended to assist in the understanding of trends and significant changes in or results of operations and the financial condition for the periods presented. The MD&A has been prepared by management as at November 6, 2009 in accordance with Canadian Generally Accepted Accounting Principles ("GAAP") and should be read in conjunction with the unaudited interim consolidated financial statements (as at September 30, 2009 and for the three and nine months ended 2009 and 2008), the audited consolidated financial statements as at December 31, 2008 and 2007, and for the years then ended, respectively, together with accompanying notes, the Statement of Reserves Data and Other Oil and Gas Information on December 31, 2008 and the Annual Information Form dated April 1, 2009. These documents and additional information about Epsilon Energy Ltd. ("Epsilon" or the "Corporation") are available on SEDAR at [www.sedar.com](http://www.sedar.com). Unless stated otherwise, all references to monetary values are in United States dollars.

### Cautionary Statement Regarding Forward Looking Information and Statements

Certain statements contained in this report constitute forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions and statements relating to matters that are not historical facts constitute "forward looking information" within the meaning of applicable Canadian securities legislation. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated. Such forward-looking statements are based on reasonable assumptions but no assurance can be given that these expectations will prove to be correct and the forward-looking statements included in this report should not be unduly relied upon. These statements are made only as of the date of this report.

In particular, this report contains forward-looking statements including, but not limited to, the following:

- oil and natural gas production rates;
- commodity prices for crude oil or natural gas;
- supply and demand for oil and natural gas;
- the estimated quantity of oil and natural gas reserves, including reserve life;
- capital expenditure programs;
- future exploration, development and production costs;
- timing of drilling plans;
- planned construction and expansion of facilities;
- plans for and results of exploration and development activities;
- expectations regarding the Corporation's ability to raise capital and to continually add to oil and natural gas reserves through acquisitions, exploration and development; and
- treatment under governmental regulatory regimes and tax laws.

The Corporation's 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 report:

- general economic, political, market and business conditions;
- risks inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for capital, acquisitions of reserves, undeveloped lands, drilling equipment and skilled personnel;
- geological, technical, drilling and processing problems;
- incorrect assessments of the value of acquisitions;

- the availability of capital on acceptable terms;
- volatility in market prices for oil and natural gas;
- reliance on key operational and management personnel;
- actions by governmental authorities, including regulatory, environmental and taxation policies;
- fluctuations in foreign exchange, interest rates and stock market volatility; and
- other risk factors discussed under “*Risk Factors*” within the Corporation’s Annual Information Form dated April 1, 2009.

These factors are not all inclusive. Except as required under applicable securities laws, the Corporation undertakes no obligation to update or revise any forward-looking statements.

Unless otherwise indicated, all dollar values in this MD&A are, with the exception of per unit amounts, expressed in thousands of U.S. dollars.

### **Corporate Overview**

Epsilon is engaged in the acquisition, exploration, development and production of natural gas reserves targeting the Marcellus shale. The Corporation also has participating interests and production sharing agreements in other natural gas and oil plays within North America, the Middle East, and Africa. Established in 2005, the Corporation has been a producer of natural gas and oil since 2006. Epsilon’s ongoing business strategy involves focused targeting of lower risk natural gas properties within the Marcellus shale and other parts of the United States and Canada, as well as the high potential oil & gas properties in the Middle East and Africa with the goal of converting its leasehold interests into proven natural gas and oil reserves, followed by production that optimizes cash flow and return on investment. The common shares of Epsilon trade on The Toronto Stock Exchange under the symbol “EPS”. Also refer to “*Risk Factors*” in the Corporation’s Annual Information Form dated April 1, 2009.

### **Recent Events**

Epsilon announced on November 5 that it has sent a letter to the Ministry of Oil and Gas, Sultanate of Oman stating that Epsilon is withdrawing from the Exploration and Production Sharing Agreement (“EPSA”) covering Block 55, where it is the official operator.

### **Overall Performance**

During the first nine months of 2009, the Corporation generated a net loss of \$14,492 as compared to a \$3,727 net profit for the first nine months of 2008. At September 30, 2009, the Corporation had a working capital deficit (inclusive of restricted cash) of \$347, as compared to \$15,862 of surplus working capital (inclusive of restricted cash) at December 31, 2008.

### **Operational Outlook and Property Overview**

A summary of Epsilon’s projects by country are as follows:

#### ***United States***

##### *Pennsylvania Marcellus Shale*

As of September 30, 2009, the Corporation had acquired approximately 15,400 gross (15,200 net) leasehold acres in Pennsylvania where the Corporation as an operator, holds a 100% working interest. The Corporation is focusing its current development efforts in the Marcellus shale on its Highway 706 project in northeastern Pennsylvania. To date, the Corporation has drilled eight wells in Highway 706. Its first compressor is now operational and has reached its capacity of just over 6 Mmcf per day. The capacity of the first compressor has been achieved from the gas flow of four wells consisting of one short stage horizontal well, a one stage horizontal well, where the corporation is planning for additional frac stages, and two vertical wells. The Corporation has completed a two stage frac on the last of its drilled eight wells (La Rue 1B). The Corporation is currently installing a second compressor that will be operational in the fourth quarter of 2009.

On September 18, the Corporation entered into an agreement for the sale of approximately 3,700 net leasehold non-core acres located within Lycoming, Sullivan and Columbia counties in eastern Pennsylvania to an unrelated third party purchaser for \$3,400 per net leasehold acre. On October 16, 2009, the sale was executed and the Corporation received \$10,751 for approximately 3,160 acres. The purchaser is continuing due diligence for the balance of acreage. After the sale, Epsilon's net leasehold acreage in Pennsylvania stands at approximately 11,500 acres.

#### *New York*

In New York, where the Corporation holds an interest in approximately 30,200 gross (14,700 net) acres, the Corporation's acreage is prospective for natural gas production in both the Marcellus shale, (shallow unconventional natural gas play) and the Trenton-Black River formation (deep conventional natural gas play).

#### *NY Marcellus Shale*

In NY Marcellus Shale, where the Corporation holds approximately 50% interest in the leasehold and is the operator, it continues to evaluate potential exploration, development and production opportunities in the Marcellus shale, including but not limited to, participating in competitor wells, developing its existing leasehold acreage and/or entering in joint ventures with other companies.

During 2008, the Corporation participated in drilling one non-operated well (.03 net) in the Marcellus shale, which had a favorable production test and is currently shut in waiting on production infrastructure. Based on the positive test results from that well, the Corporation has commenced the early stages of forming a large Marcellus shale project, including staking well locations, planning infrastructure and seeking regulatory approvals. Marcellus shale drilling permits utilizing larger hydro-fractures are currently on hold pending completion of a Supplemental Generic Environmental Impact Statement by the New York Department of Environmental Conservation. See "*Commitments and Contingencies – New York – Trenton-Black River Well Units*".

#### *NY Trenton-Black River*

The Corporation is also focused on exploration of the prolific Trenton-Black River formation, a deep conventional natural gas reservoir target. The Corporation holds various non-operated working interests with multiple operators in well units from less than 1%, up to approximately 12%.

At September 30, 2009, net production from Trenton-Black River formation was approximately 0.6 Mmcf/d. Due to its current focus on the Marcellus shale in Pennsylvania and New York, the Corporation is not allocating a significant amount of capital to fund participation in drilling future wells targeting the Trenton-Black River formation in New York. See "*Commitments and Contingencies – New York – Trenton-Black River Well Units*".

#### *Ohio*

The Bailey's Mill project is located in Belmont and Monroe counties and consists of approximately 38,800 gross (8,500 net) leasehold acres, in which the Corporation holds a 25% non-operated working interest. Due to its current focus on the Marcellus shale in Pennsylvania and New York, the Corporation does not anticipate allocating a significant amount of funds to continue participating in drilling future wells on its Bailey's Mill project.

#### *West Virginia*

On June 16, 2009, the Corporation sold all of its oil and natural gas properties in West Virginia to an unrelated third party for a net amount of \$12,932 and recognized a loss of \$9,743 on the transaction. Included in the transaction were 36,535 gross (14,717 net) leasehold acres, 112 gross (59.59 net) wells and a 63% interest in the Blue Jacket gathering system. The property sale represented approximately 55% of the Corporation's North American proved oil and natural gas reserves at December 31, 2008, and approximately 50% of its daily natural gas production at the time of the sale. The Corporation has

deployed the proceeds of the transaction primarily to further its development activities in the Marcellus shale in Pennsylvania.

## *Canada*

### *Saskatchewan*

On August 28, 2008, the Corporation entered into an agreement with a private Canadian company covering joint oil and natural gas exploration and development activities in a 63,360 gross acre Area of Mutual Interest (“**AMI**”) covering the Bakken oil play in southeast Saskatchewan province. Under the terms of the agreement, the Company has the ability to earn a 50% interest in approximately 8,960 gross (7,806 net) acres within the AMI. Drilling operations on the first earning well commenced during August 2009 and is expected to cost approximately CDN\$2,400. The first well, the Torquay, has been drilled horizontally, fractured and is currently being evaluated. The Corporation estimates it will spend a minimum amount of approximately \$5,000 on this project. The project lies within the favorable Saskatchewan province royalty area. See “*Commitments and Contingencies – Bakken Shale Drilling Commitment*”.

### *Quebec*

The Corporation has an elective participating interest of up to 25% in a portion of Gastem, Inc.’s (TSXV: GMR) leasehold acreage in the St. Lawrence Lowlands (covering Utica shale and Trenton-Black River targets) and in the Gaspé Peninsula (covering Silurian and Devonian targets). Within Gastem Inc.’s St. Lawrence Lowlands leasehold acreage, Forest Oil Corporation recently spent CDN\$10,000 to earn a 60% interest in what is now referred to as the Yamaska project. The Corporation went non-consent on the first two exploratory wells drilled within the Yamaska project, but has elected to participate in future operations with a 5% working interest.

## *Yemen – Block 41*

During 2007, the Corporation acquired a 57.14% paying interest and 50% undivided percentage interest in the rights, duties, interests and obligations under the Block 41 Production Sharing Agreement (“**Block 41 PSA**”) covering approximately 5,600 square kilometers (1.4 million acres), which is located onshore in Yemen. The Corporation is the operator of Block 41 and is currently evaluating the Al Waya field to determine the additional work required to substantiate developing this field.

In addition, from mid-2008 through the first quarter of 2009, the Corporation drilled four exploratory wells (Al Waya #2, Kaninah #1, West Mahrawa #2 and Mukulla #1) on Block 41, all of which were non-commercial despite having encouraging oil and natural gas shows. The Corporation is currently evaluating the data obtained to date from its operations on Block 41 to determine the most effective way to proceed with its future exploration activities on Block 41, if any.

As of the date of this report, substantially all seismic activity has been focused on the western half of the middle portion of Block 41 where the Al Waya field discovery is located, which represents approximately one-third of the concession. There has been little or no exploratory activity conducted on the other portions of Block 41. As such, management believes there may be potential for substantial oil and natural gas resources yet to be exploited on Block 41 beyond the prospects identified on 2D seismic to date.

### *OGMC Default*

As at September 30, 2009, Oil and Gas Mine Company (“**OGMC**”), a non-operated joint interest owner in Block 41, owed the Corporation \$4,449, for their pro-rata share of costs pertaining to Block 41 in Yemen, all of which has been deemed to be in default and reclassified as long-term receivable. During the second quarter of 2009, OGMC made a partial payment of \$2,000 pertaining to the \$5,591 balance due at December 31, 2008. The Corporation has commenced legal action to pursue acquisition of OGMC’s interest in Block 41 in full satisfaction of the amount due.

### ***Ethiopia – Northwest Area Study Agreement***

On May 14, 2009, the Corporation announced that it had signed a Production Sharing Agreement (“PSA”) with the Ministry of Mines and Energy (the “Ministry”) in Democratic Republic of Ethiopia. The PSA covers an area of 79,345 square kilometers (30,635 square miles) in northwest Ethiopia. Terms of the PSA include an initial three-year exploration period that includes a minimum financial commitment of \$3,000 to drill one exploratory well and to acquire a minimum of 200 kilometers of 2D seismic. In the event the Company makes a commercial discovery, the initial percentage split of profit oil and/or gas will be 80% for Epsilon and 20% for the Ministry.

### ***Oman - Block 55***

On January 26, 2009, the Corporation was awarded a 100% operated working interest in Block 55, an onshore oil and natural gas concession in Oman, in return for a \$25,500 work commitment over three years and sharing in commercial production, if any, which would be shared over a 20 year contractual term.

In an effort to conserve its capital, as of September 30, 2009, the Corporation had not yet paid any up-front costs for Block 55 to the government of Oman. As at September 30, 2009, a total of \$2,250 of such up-front costs had been capitalized, but not paid. Per the contract covering Block 55, the Corporation is subject to a London Interbank Offered Rate (“LIBOR”) plus 5% penalty on the outstanding unpaid amounts. At September 30, 2009, the Corporation has expensed an overall late penalty of \$66 pertaining to such unpaid amounts.

The Corporation is the official operator of Block 55 and is considering bringing in industry partners, raising additional capital, or a combination of both to fund the exploitation of this concession. Leaving aside the aforementioned up-front costs, the Corporation does not expect to spend a significant amount of additional capital towards this concession until 2010 or later.

## **RESULTS of OPERATIONS**

*(Amounts are rounded to thousands of U.S. dollars, unless stated otherwise)*

The following discussion encompasses the Corporation’s revenues and costs of operations. Unless noted otherwise, the discussion pertains to the Corporation’s Appalachian basin segment in the United States, as all other identified geographical operating segments were essentially in the start-up phase during the presented periods and had no reportable revenues or operating costs during the presented periods.

### **TOTAL REVENUES**

	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30,</b>		<b>September 30,</b>	
	<b>2009</b>	<b>2008</b>	<b>2009</b>	<b>2008</b>
<b>Total Revenues</b>	<b>607</b>	<b>2,476</b>	<b>3,046</b>	<b>6,387</b>
Net natural gas production (Mcf) ...	182,086	244,629	557,423	532,062
Average natural gas price (\$/Mcf) ..	3.33	8.12	5.48	9.61
End of period net production exit rate (Mcf/d).....	2,891	2,774	2,891	2,774
Net oil production (bbls).....	2	4,642	(180)	13,740
Average oil price (\$/bbl).....	53.54	105.50	49.50	92.58

***Third Quarter 2009 Compared to Third Quarter 2008***

Total revenues decreased by \$1,869 from \$2,476 in the third quarter of 2008 to \$607 in the third quarter of 2009 primarily due to:

- A 59% decrease in the average natural gas price received during the third quarter of 2009 as compared to the third quarter of 2008 accounting for \$872 of variance.
- 62,532 Mcfe decrease in natural gas production volume mainly due to the sale of West Virginia assets in the second quarter of 2009, which accounted for \$507.
- And \$490 due to the absence of oil sales from West Virginia assets.

***Nine Months Ended September 30, 2009 compared to 2008***

Total revenues decreased by \$3,341 from \$6,387 in the first nine months of 2008 to \$3,046 in the first nine months 2009 primarily due to:

- A 43% decrease in the average natural gas price received during the first nine months of 2009 as compared to the first nine months of 2008 accounting for \$2,298 of decrease that was partially offset by an increase in volume of 24,283 Mcf (\$233) in natural gas production in 2009.
- A \$1,276 reduction of oil revenues in the first nine months of 2009, as compared to the first nine months of 2008. The oil revenues were from West Virginia properties that the Corporation sold on June 16, 2009.

***PROJECT OPERATING COSTS***

	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2009</b>	<b>2008</b>	<b>2009</b>	<b>2008</b>
<b>Project operating costs.....</b>	<b>188</b>	<b>671</b>	<b>1,040</b>	<b>1,339</b>

Project operating costs consist of lease operating expenses necessary to extract gas and oil, including transporting it to a sales point and production taxes assessed by the state in which production occurs. Substantially all production taxes apply to the states of Ohio and West Virginia, where the production tax rate is a certain percentage of gross revenues. In New York and Pennsylvania, the Corporation's wells are exempt from production taxes.

***Third Quarter 2009 Compared to Third Quarter 2008***

Total project operating costs decreased by \$483 from \$671 in the third quarter of 2008 to \$188 in the third quarter of 2009 primarily due to:

- A decrease of \$460 of lease operating expenses due to the sale of West Virginia property, which was partially offset by the addition of \$91 operating expenses after the commencement of operations at Epsilon's 100% owned Highway 706 project in Pennsylvania.
- A decrease of \$114 in production taxes during the third quarter of 2009 as compared to the third quarter of 2008, as the taxes in 2008 relates primarily to West Virginia that was sold in 2009. In 2009, there were no property taxes in Pennsylvania.

***Nine Months Ended September 30, 2009 compared to 2008***

Project operating costs decreased by \$299 from \$1,339 in the first nine months of 2008 to \$1,040 in the first nine months 2009 primarily due to:

- A decrease of \$342 of lease operating expenses due to the sale of West Virginia property, which was partially offset by the addition of \$212 operating expenses after the commencement of operations at Epsilon's 100% owned Highway 706 project in Pennsylvania.

- A decrease of \$169 in production taxes and royalty expenses during the first nine months of 2009 as compared to the first nine months of 2008, due to 43% lower average natural gas prices and no production taxes during the third quarter of 2009.

***IMPAIRMENT OF UNPROVED PROPERTY***

	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30,</b>		<b>September 30,</b>	
	<b>2009</b>	<b>2008</b>	<b>2009</b>	<b>2008</b>
<b>Impairment of unproved property .....</b>	<b>581</b>	<b>-</b>	<b>2,753</b>	<b>-</b>

***Third Quarter 2009 Compared to Third Quarter 2008***

During the third quarter of 2009 the Corporation recorded an unproved property impairment of \$581 pertaining to Block 41 in Yemen, where it continued to have operations. There were no unproved property impairments during the third quarter of 2008.

***Nine Months Ended September 30, 2009 compared to 2008***

During the first nine months of 2009 the Corporation recorded an unproved property impairment of \$2,753 pertaining to Block 41 in Yemen, where it drilled an exploratory dry hole and continued to have operations. There were no unproved property impairments during the first nine months of 2008.

***DEPLETION, DEPRECIATION AND ACCRETION (“DD&A”)***

	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30,</b>		<b>September 30,</b>	
	<b>2009</b>	<b>2008</b>	<b>2009</b>	<b>2008</b>
<b>Total Depletion, Depreciation and Accretion</b>	<b>1,212</b>	<b>737</b>	<b>2,521</b>	<b>1,745</b>

In line with the Full Cost Accounting principle, the Corporation capitalizes all costs related to the exploration for and development of natural gas and crude oil reserves. The capitalized costs and future development costs are depleted on the unit-of-production method based on estimated proved reserves. Costs of significant unproved properties, net of impairments, are excluded from the depletion, depreciation and accretion calculation. See section “*Full Cost Accounting*” below.

Substantially all depreciation expense amounts pertained to the Corporation’s office furniture and fixtures, computer hardware and computer software, while all accretion expense amounts pertain to the amortization of the Corporation’s asset retirement obligations.

***Third Quarter 2009 Compared to Third Quarter 2008***

The Depletion, Depreciation and Accretion (“**DD&A**”) expense increased by \$475 from \$737 in the third quarter of 2008 to \$1,212 in the third quarter of 2009 primarily due to the change in depletion expense rate from \$2.60/Mcfe for the third quarter of 2008 to a rate of \$6.33/Mcfe for the third quarter of 2009. The higher depletion expense rate was mainly due to the sale of proved and probable reserve in West Virginia during the second quarter of 2009, which reduced the Corporation’s proved and probable reserves for purposes of depletion expense calculation.

***Nine Months Ended September 30, 2009 compared to 2008***

The DD&A expense increased by \$776 from \$1,745 in the first nine months of 2008 to \$2,521 in the first nine months 2009 primarily due to the change in depletion expense rate from \$2.71/Mcfe for the nine months ended September 30, 2008 to a rate of \$6.33/Mcfe for the first nine months of 2009. The higher depletion expense was mainly due to the sale of proved and probable reserve in West Virginia during the second quarter of 2009, which reduced the Corporation's proved and probable reserves for purposes of depletion expense calculation.

**GENERAL AND ADMINISTRATIVE**

	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2009</b>	<b>2008</b>	<b>2009</b>	<b>2008</b>
<b>Total General and Administrative.....</b>	<b>1,369</b>	<b>1,523</b>	<b>3,841</b>	<b>5,699</b>

General and Administrative ("G&A") consists of general corporate expenses such as compensation, legal fees, accounting fees, professional fees, consulting services, travel and other related corporate costs such stock options granted.

***Third Quarter 2009 Compared to Third Quarter 2008***

The G&A expenses decreased by \$154 from \$1,523 in the third quarter of 2008 to \$1,369 in the third quarter of 2009 primarily due to a decrease of \$112 in stock-option expense and continuation of cost containment measures implemented during the second quarter of 2009.

***Nine Months Ended September 30, 2009 compared to 2008***

The G&A expenses decreased by \$1,858 from \$5,699 in the first nine months of 2008 to \$3,841 in the first nine months 2009 primarily due to a \$1,311 decrease in general corporate expenses as a result of cost containment measures that were implemented during the second and third quarters of 2009 and a reduction of \$547 in stock-option expense.

**INTEREST INCOME (EXPENSE)**

	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2009</b>	<b>2008</b>	<b>2009</b>	<b>2008</b>
<b>Interest Income (Expense) .....</b>	<b>(55)</b>	<b>308</b>	<b>(241)</b>	<b>1,038</b>

***Third Quarter 2009 Compared to Third Quarter 2008***

During the third quarter of 2008, Epsilon earned \$308 of interest income, while during the third quarter of 2009 Epsilon incurred \$55 of interest expense due to reduction of cash balances that were used for funding the Corporation's operations.

***Nine Months Ended September 30, 2009 compared to 2008***

During the first nine months of 2008 Epsilon earned net interest income of \$1,038 while the Corporation incurred net interest expense of \$241 during the first nine months of 2009 due to reduction of cash balances that were used for funding the Corporation's operations.

***GAIN (LOSS) ON SALE OF ASSETS***

	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2009</b>	<b>2008</b>	<b>2009</b>	<b>2008</b>
<b>Gain (Loss) on Sale of Assets</b>	<b>(14)</b>	<b>-</b>	<b>(9,743)</b>	<b>5,085</b>

***Third Quarter 2009 Compared to Third Quarter 2008***

During the third quarter of 2009, Epsilon incurred \$14 loss on sale of assets, reflecting an adjustment to the sale of West Virginia properties that were sold in the second quarter of 2009, while there was no gain or loss recorded during the third quarter of 2008.

***Nine Months Ended September 30, 2009 compared to 2008***

During the first nine months of 2009 the Corporation recorded a net loss of \$9,743 on the sale of its oil and natural gas property interests in West Virginia. A gain of \$5,085 was recorded during the first nine months of 2008, reflecting a gain on the sale of non-core unproved leasehold in the Appalachian basin.

***INCOME TAXES***

	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2009</b>	<b>2008</b>	<b>2009</b>	<b>2008</b>
<b>Income Tax Recovery</b>	<b>-</b>	<b>-</b>	<b>2,600</b>	<b>-</b>

Due to the volatile nature of oil and natural gas exploration, development, and production activities, there are numerous uncertainties with respect to projecting future revenues and operating costs, which are integral components of future net income projections. These uncertainties include such items as production levels, capital expenditure levels, oil and natural gas commodity prices, reserve estimates, and lease operating costs. Actual results may vary significantly from projected amounts.

During the first nine months of 2009 the Corporation recorded a future income tax recovery of \$2,600. This amount represents the Corporation's recognition of deductible temporary differences (mainly pertaining to the sale of its oil and natural gas property interests in West Virginia) to the extent to offset the taxable temporary differences and recording of a valuation allowance for any remaining deductible temporary differences. Deferred tax assets were not booked as they were not assessed by the management to be more likely than not to be realized as assets.

Determination of the Corporation's income tax and other tax liabilities requires the interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ from that estimated and recorded by the Corporation's management.

**NET INCOME / (LOSS)**

	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30,</b>		<b>September 30,</b>	
	<b>2009</b>	<b>2008</b>	<b>2009</b>	<b>2008</b>
<b>Net Income / (Loss) .....</b>	<b>(2,812)</b>	<b>(148)</b>	<b>(14,492)</b>	<b>3,727</b>
<b>Net Income / (Loss) per share .</b>				
<b>Basic.....</b>	<b>(0.06)</b>	<b>(0.00)</b>	<b>(0.29)</b>	<b>0.08</b>
<b>Diluted .....</b>	<b>(0.06)</b>	<b>(0.00)</b>	<b>(0.29)</b>	<b>0.07</b>

**Third Quarter 2009 Compared to Third Quarter 2008**

Net loss increased by \$2,664 from \$148 (\$0.00 per share) in the third quarter of 2008 (\$0.06 per share) to \$2,812 in the third quarter of 2009 primarily due to:

- \$1,869 attributable to lower revenue
- A \$581 impairment pertaining to Block 41 in Yemen in the third quarter of 2009
- \$475 higher DD&A costs and;
- \$54 interest expense booked in the third quarter of 2009 versus \$308 interest revenue in the third quarter of 2008
- Above factors were partially offset by \$483 lower operating costs and \$154 lower G&A expenses, all of which were discussed above.

**Nine Months Ended September 30, 2009 compared to 2008**

The net loss during the first nine months of 2009 of \$14,492 (\$0.29 per share) as compared to net income of \$3,727 (\$0.08 basic per share and \$0.07 diluted per share) for the first nine months of 2008 was primarily attributable to a combination of following factors, all of which were discussed earlier:

- A recorded loss of \$9,743 on the sale of the Corporation's oil & gas property interests in West Virginia in June 2009;
- \$5,085 gain booked on the sale of non-core unproved leasehold interests in Ohio in 2008
- \$3,341 attributable to lower revenue
- \$2,753 impairment pertaining to Block 41 in Yemen during the first nine months of 2009
- \$241 interest expense booked in the first nine months of 2009 versus \$1,038 interest revenue in the first nine months of 2008
- Partially offset by \$2,600 income tax recovery recorded in 2009 pertaining to the sale of property interests in West Virginia and \$1,858 lower G&A costs during the first nine months of 2009 compared to the first nine months of 2008.

## SELECTED QUARTERLY INFORMATION

Summary quarterly information is presented in the table below. All amounts rounded to thousands of dollars, except for per share amounts.

(in thousands of dollars, except shares outstanding and per share amounts)	Three months Ended							
	Dec 31, 2007	Mar 31, 2008	Jun 30, 2008	Sep 30, 2008	Dec 31, 2008	Mar 31, 2009	Jun 30, 2009	Sep 30, 2009
<b>Revenues:</b>								
Gas .....	1,024	1,297	1,831	1,986	1,855	1,650	665	607
Oil .....	-	240	543	490	(229)	(15)	6	-
Gathering fees, net.....	-	-	-	-	287	72	61	-
<b>Total revenues.....</b>	<b>1,024</b>	<b>1,537</b>	<b>2,374</b>	<b>2,476</b>	<b>1,913</b>	<b>1,707</b>	<b>732</b>	<b>607</b>
<b>Operating costs</b>								
Impairment of unproved properties .....	-	-	-	-	34,099	-	2,172	581
DD&A.....	736	428	580	737	327	697	612	1,212
G&A.....	2,708	1,538	2,637	1,524	1,820	1,306	1,166	1,369
<b>Cost of operations.....</b>	<b>3,652</b>	<b>2,247</b>	<b>3,604</b>	<b>2,932</b>	<b>36,699</b>	<b>2,470</b>	<b>4,335</b>	<b>3,350</b>
Operating loss .....	(2,628)	(710)	(1,230)	(456)	(34,786)	(763)	(3,603)	(2,743)
Gain (loss) on sale of assets .....	-	(1)	5,086	-	(72)	-	(9,728)	(14)
Other income (loss).....	554	427	302	308	43	(72)	(114)	(55)
<b>Net income (loss) before income taxes.....</b>	<b>(2,074)</b>	<b>(284)</b>	<b>4,158</b>	<b>(148)</b>	<b>(34,815)</b>	<b>(835)</b>	<b>(13,445)</b>	<b>(2,812)</b>
Income tax (recovery).....	-	-	-	-	2,600	-	(2,600)	-
<b>Net (loss) income.....</b>	<b>(2,074)</b>	<b>(284)</b>	<b>4,158</b>	<b>(148)</b>	<b>(37,415)</b>	<b>(835)</b>	<b>(10,845)</b>	<b>(2,812)</b>
<b>Basic weighted average</b>								
# of shares outstanding	45,698,323	45,698,323	45,698,323	51,315,323	51,315,323	51,315,323	51,315,323	51,315,323
Basic net (loss) income per share.....	(0.08)	(0.01)	0.09	0.00	(0.79)	(0.02)	(0.22)	(0.06)
<b>Diluted average # of shares outstanding.....</b>								
Weighted average net (loss) income per share	(0.08)	(0.01)	0.09	0.00	(0.79)	(0.02)	(0.22)	(0.06)

## Liquidity and Capital Resources

At September 30, 2009, the Corporation had a working capital deficit (inclusive of restricted cash) of \$347, as compared to \$15,862 of surplus working capital (inclusive of restricted cash) at December 31, 2008. The \$16,209 decrease in working capital at September 30, 2009, as compared to December 31, 2008 is primarily attributable to \$25,908 spent on capital expenditures during the first nine months of 2009 and payment of its line of credit at TD bank in full. This was offset by a net amount of \$12,932 received from the sale of the Corporation's oil and natural gas property interests in West Virginia.

The Corporation has continued with its plan to sell its non-core assets to fund future operations and repay debt. On October 16, 2009 the Corporation received \$10,751 from the sale of non-core leasehold acres in Pennsylvania that was then used to pay the outstanding balance of \$7,500 with regards to its line of credit at Northwestern Bank. As of November 6, 2009, the Corporation is debt free. (See Notes 4 and 12 of Unaudited Interim Consolidated Financial Statements for the third quarter of 2009). It is expected that cash on hand and cash flow from sale of natural gas should be more than sufficient to fund the Corporation's exploration plans in the Pennsylvania Marcellus shale project.

***Oil and Natural Gas Property Investments***

	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30,</b>		<b>September 30,</b>	
	<b>2009</b>	<b>2008</b>	<b>2009</b>	<b>2008</b>
<b>Oil and natural gas property investments .....</b>	<b>6,718</b>	<b>5,093</b>	<b>25,908</b>	<b>21,873</b>

***Third Quarter 2009 Compared to Third Quarter 2008***

Total oil and natural gas property investments increased by \$1,625 from \$5,093 in the third quarter of 2008 to \$6,718 in the third quarter of 2009 primarily due to the payment of \$2,214 for its AMI in the Bakken shale, partially compensated by lower capital investment in the Corporation's Middle Eastern operations.

***Nine Months Ended September 30, 2009 compared to 2008***

Total oil and natural gas property investments increased by \$4,035 from \$21,873 in the first nine months of 2008 to \$25,908 in the first nine months 2009 primarily due to:

- Acceleration of operations in the Highway 706 project in Pennsylvania in 2009 versus 2008
- Drilling costs of the first well in the Bakken shale
- Partially compensated by lower capital investment in the Corporation's Yemen, West Virginia, and New York projects.

## Reportable Geographical Operating Segments

As of September 30, 2009, the Corporation held interests in the following countries: United States, Canada, Yemen, Ethiopia, and Oman. From its inception through the first nine months of 2009, the Corporation's oil and natural gas revenues have been derived solely from the Appalachian basin in the United States.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
<b>Reportable Segments:</b>				
United States:				
Revenues .....	\$ 606	\$ 2,476	\$ 3,046	\$ 6,387
Operating costs .....	188	671	1,040	1,339
Capital expenditures .....	2,920	4,620	17,142	20,292
Canada:				
Revenues .....	-	-	-	-
Operating costs .....	-	-	-	-
Capital expenditures .....	2,257	18	2,307	18
Yemen:				
Revenues .....	-	-	-	-
Operating costs .....	-	-	-	-
Capital expenditures .....	581	3,308	2,753	8,454
Ethiopia:				
Revenues .....	-	-	-	-
Operating costs .....	-	-	-	-
Capital expenditures .....	13	104	243	116
Oman:				
Revenues .....	-	-	-	-
Operating costs .....	-	-	-	-
Capital expenditures .....	120	110	2,878	185
Other International:				
Revenues .....	-	-	-	-
Operating costs .....	-	-	-	-
Capital expenditures .....	21	82	64	82
<b>Total Reportable Segments:</b>				
Revenues .....	607	2,476	3,046	6,387
Operating costs .....	188	671	1,040	1,339
Capital expenditures .....	5,912	8,244	25,387	29,148

## Critical Accounting Estimates

The Corporation's financial and operating results incorporate certain estimates including:

- Estimated revenues, royalties and operating costs on production as at a specific reporting date but for which actual revenues and costs have not yet been received;
- Estimated capital expenditures on projects that are in progress;
- Estimated depletion, depreciation and accretion that are based on estimates of oil and gas reserves that the Corporation expects to recover in the future;

- Estimated value of asset retirement obligations that are dependent upon estimates of future costs and timing of expenditures; and
- Estimated future recoverable value of property, plant and equipment.

Below are explanations of significant critical accounting estimates. Also see Note 3 – “*Accounting Pronouncements*” within the annual consolidated financial statements for the year ended December 31, 2008.

#### *Full Cost Accounting*

The Corporation utilizes the full cost method of accounting for its crude oil and natural gas properties. Accordingly, all costs related to the exploration for and development of crude oil and natural gas reserves, whether successful or not, are capitalized. The capitalized costs and future development costs are depleted on the unit-of-production method based on estimated proved reserves. Costs of significant unproved properties, net of impairments, are excluded from the depletion, depreciation and accretion calculation. Properties excluded from the depletion calculation are assessed periodically to ascertain whether impairment has occurred.

The carrying amount of crude oil and natural gas properties may not exceed their recoverable amount (the “**Ceiling Test**”). The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves and the lower of cost or market of unproved properties exceeds the carrying value of the crude oil and natural gas assets. If the carrying value of the crude oil and natural gas assets is assessed to not be recoverable, an impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves and the lower of cost or market of unproved properties. The cash flows are estimated using future product prices and costs, which are discounted using a risk-free rate of interest. At December 31, 2008, the Ceiling Test for the Corporation’s Yemen oil and natural gas properties failed, resulting in an impairment of \$34,099. In addition, during the first nine months of 2009, the Corporation recorded an impairment of \$2,753 pertaining to Block 41 in Yemen, where it drilled an exploratory dry hole.

Proceeds from the sale of oil and natural gas property interests are credited against the applicable country cost center. A gain or loss is recognized only if the resulting credit of proceeds from the sale results in a change to the depletion rate of the associated country cost center of 20% or more. As of September 30, 2009, the Corporation recognized a loss on the sale of its West Virginia oil and natural gas property interests of \$9,743 after it was determined that the change in depletion rate resulting from the proceeds of the sale of the Corporation’s oil and natural gas property interests in West Virginia exceeded the aforementioned 20% threshold.

The alternative method of accounting for crude oil and natural gas properties is the successful efforts method. The major difference in applying the successful efforts method is that exploratory dry holes and geological and geophysical exploration costs are charged against net earnings in the year they are incurred rather than being capitalized. The use of the full cost method usually results in higher capitalized costs and higher DD&A rates than the successful efforts method.

#### *Crude Oil and Natural Gas Reserves*

The Corporation retains qualified independent reserves evaluators to estimate the Corporation's proved and probable crude oil and natural gas reserves. The estimation of reserves involves the exercise of judgment. Forecasts are based on engineering data, expected rates of production and the timing of future capital expenditures, all of which are subject to major uncertainties and interpretations. The Corporation expects that over time its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of DD&A and for determining potential asset impairment. For example, a revision to the reserve estimate would result in a higher or lower DD&A charge to net earnings. Downward revisions to reserve estimates could also result in a write-down of crude oil and natural gas properties.

When estimating oil and natural gas reserves and their associated net cash flows, there are numerous factors that contain significant measurement uncertainties that are beyond the Corporation's control. Those factors include, but are not limited to, volumetric reserve estimates, future commodity pricing, future operating costs and the timing of and amount of future capital costs. When assessing the fair market value of reserves, additional factors must be considered such as current market conditions, credit markets, location of reserves, classification of reserves based on risk of recovery, political risk and other factors, all of which may contribute to significant measurement uncertainty. Due to the complexity involved, reserve estimates and fair market value estimates will vary greatly from one reserve estimator to another.

#### *Asset Retirement Obligations ("ARO")*

The Corporation is required to recognize a liability for future abandonment and site restoration costs associated with the Corporation's crude oil and natural gas properties in accordance with existing laws, contracts or other policies. The fair value of the estimated ARO is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related asset known as the asset retirement cost, which is depleted on a unit-of-production basis over the life of the reserves. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings, and for revisions to the estimated future cash flows, if any. Actual costs incurred upon settlement of the obligations are charged against the liability. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances, industry practices and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the Corporation's total ARO amount. These individual assumptions can be subject to change based on experience. Restoration technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. The Corporation estimates future retirement costs based on current estimates adjusted for inflation and credit risk, which are expected to be incurred at the end of the associated properties economic life. The estimates for inflation and credit risk used to calculate ARO are also subject to measurement uncertainty. The Corporation assumed an estimated credit adjusted risk-free rate calculated on a yearly basis and an estimated inflation rate of 2% to calculate the net present value of the asset retirement obligations. The total future ARO was estimated based on the Corporation's net ownership interest in all wells and facilities in the Appalachian basin in the U.S., and includes estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods.

The Corporation has estimated the net present value of its total ARO for wells drilled on its projects in the Appalachian basin to be \$230 and \$320 at September 30, 2009 and December 31, 2008, respectively, based on estimated total undiscounted future liabilities of \$717 and \$1,075 at September 30, 2009 and December 31, 2008, respectively. The reduction of ARO at September 30, 2009, as compared to December 31, 2008, was the direct result of the sale of the Corporation's West Virginia assets that was completed during June 2009.

No provision was made for asset retirement obligations with respect to the Corporation's Yemen properties, where the contracts with the government of Yemen stipulate that all property and equipment will be transferred to the government of Yemen at the end of the contract term. Asset retirement activities during the contract term in Yemen, if any, are fully recoverable from the proceeds of cost oil. The EPSA in Oman contains provisions whereby the operator must fund estimated abandonment costs during the five calendar years prior to the expiration of the EPSA. Since the Corporation has yet to commence drilling operations in Oman, there were no provisions made for ARO liabilities in Oman as of September 30, 2009.

#### *Stock-Based Compensation*

The Corporation records stock-based compensation expense using the fair value method. The fair value of an option is calculated at the grant date using the Black-Scholes option pricing model and expensed over the vesting term of the option. The Corporation records the cumulative stock-based compensation as a contributed surplus. When options are exercised, contributed surplus is reduced and share capital is increased by the amount of accumulated stock-based compensation for the exercised option. Any

consideration received on the exercise of stock options is credited to share capital. The determination of stock-based compensation expense is based on assumptions regarding stock volatility, risk-free interest rates and the term of the options. These assumptions, by their nature, are subject to measurement uncertainty. An increase in volatility, the risk-free rate or the term would increase the calculated expense.

#### *Income Taxes*

The determination of the Corporation's income and other tax liabilities requires the interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ from that estimated and recorded by the Corporation's management. A valuation allowance is recorded against any future income tax asset if the Corporation is not "more likely than not" to realize the tax deduction. The valuation allowance for income taxes, if any, is subject to measurement uncertainty pertaining to projected future production levels, future capital expenditures, future commodity prices and future operating costs, all of which could vary significantly from actual results.

### **International Financial Reporting Standards**

In February 2008, the Accounting Standards Board confirmed that all Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards ("IFRS") for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. Epsilon is continually assessing the impact of the convergence of Canadian GAAP with IFRS on the Corporation's results of operations, financial position and disclosures. Under the direction and oversight of the Board of Directors and Audit Committee, the Corporation's management has commenced the transition and is working to ensure successful implementation within the required time frame. The Corporation recognizes that the changeover to IFRS has complex implications on a combination of accounting, financial reporting, IT and business systems. Consequently, the Corporation has engaged a professional accounting firm to conduct a Business Impact Study, to assist in the development a Project Plan, and to provide assistance in considering various accounting policy decisions which will be required throughout the transition period. Corporate personnel involved with the transition project have also received appropriate training and education. The overall IFRS transition project consists of five phases: (i) Scope; (ii) Plan; (iii) Design and Build; (iv) Implement; and (v) Review. The Scope phase, which consisted primarily of identifying the significant differences between Canadian GAAP and IFRS, has been completed. The Corporation expects that the implementation of IFRS will have a moderate overall impact on Epsilon's consolidated financial statements as there are a number of differences between Canadian GAAP and IFRS applicable to the Corporation. The Corporation has concluded that the following key issues are expected to have the most significant impact on Epsilon's results of operations, financial position and disclosures:

- IFRS 1 – First-time adoption of International Financial Reporting Standards
- IFRS 6 – Exploration and evaluation of mineral resources
- IAS 16 – Property, plant and equipment
- IAS 36 – Impairment of assets
- IAS 37 – Provisions, contingent liabilities and contingent assets

### **Changes in Accounting Policies, including Initial Adoption**

#### *Goodwill and Intangible Assets*

In February 2008, the CICA issued section 3064 of the CICA Handbook "*Goodwill and Intangible Assets*", which replaces section 3062 of the CICA Handbook "*Goodwill and Other Intangible Assets*" and section 3450 of the CICA Handbook "*Research and Development Costs*". The new section of the CICA Handbook is applicable to fiscal years beginning on or after October 31, 2008 and establishes standards for recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards in the previous section 3062. On January 1, 2009, the Corporation adopted this section. This new standard did not have a material impact on the Corporation's consolidated financial statements.

### *Financial Instruments – Disclosures*

In May 2009, the CICA 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 Corporation on December 31, 2009.

#### **Disclosure Controls and Procedures**

The Corporation has evaluated the effectiveness of its disclosure controls and procedures and has concluded based on this evaluation that the disclosure controls and procedures are sufficiently effective to provide reasonable assurance that material information relating to the Corporation is made known to management and disclosed in accordance with applicable securities regulations.

The Chief Executive Officer and Chief Financial Officer, together with other members of management, having designed Internal Controls Over Financial Reporting (“**ICFR**”) to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial reporting in accordance with GAAP, have not identified any changes to the Corporation's internal control over financial reporting which would materially affect, or is reasonably likely to materially affect, the Corporation's internal control over financial reporting.

During 2008, the Corporation documented and tested its entity level and process level controls covering ICFR reporting and concluded that such controls were effective. To help insure continued adherence to established internal controls and related policies, the Corporation has initiated an internal control testing program that will be conducted throughout 2009.

### **COMMITMENTS AND CONTINGENCIES**

#### ***Bakken Shale Drilling Commitment***

The Corporation entered into an agreement with an unrelated privately held Canadian company on August 28, 2008, whereby the Corporation agreed to pay 100% of the costs to drill a minimum of two horizontal wells in the Bakken shale in order to earn a 50% working interest in acreage controlled by the unrelated private company. During the third quarter of 2009, the Corporation paid for the cost to drill the first of the two aforementioned earning wells.

#### ***Yemen- Block 41 PSA***

In accordance with the Farm-in Agreement with OGMC dated September 10, 2007 covering the Corporation's acquisition of a 57.14% paying interest in the Block 41 Production Sharing Agreement from OGMC, the Corporation is obligated to pay OGMC \$3,000 upon a Declaration of Commerciality. The \$3,000 payment will only be incurred in the event the Corporation makes a commercial oil or natural gas discovery on Block 41 and the Ministry of Minerals grants a license to commercially produce such discovery. Due to the contingent nature of this item, it is not reflected in the Corporation's Balance Sheet at September 30, 2009 and December 31, 2008.

#### ***Oman – Block 55 EPSA***

On January 26, 2009, the Corporation was awarded a 100% operated working interest in Block 55, an onshore oil and natural gas concession in Oman, in return for a \$25.5 million work commitment over three years and sharing in commercial production, if any, which would be shared over a 20 year contractual term.

In an effort to conserve its capital, as of September 30, 2009, the Corporation had not yet paid any up-front costs for Block 55 to the government of Oman. As at September 30, 2009, a total of \$2,250 of such up-front costs had been capitalized, but not paid. Per the contract covering Block 55, the Corporation is subject to a London Interbank Offered Rate ("LIBOR") plus 5% penalty on the outstanding unpaid amounts. At September 30, 2009, the Corporation has expensed an overall late penalty of \$60 pertaining to such unpaid amounts.

#### ***New York – Trenton-Black River Well Units***

During 2006, the Department of Environmental Conservation ("DEC") classified the Corporation's interest in several wells drilled prior to a statute change as an integrated non-participating owner. As a result, the Corporation was charged a non-consent penalty (300% of 100% of the total drilling and completion costs) on its pro-rata share of costs to drill and complete various wells by Fortuna Energy Inc., the operator. The Corporation believes its interest in the subject wells should have been classified as an integrated participating owner upon payment of its pro-rata share of costs, effectively negating the non-consent penalty the operator could charge prior to disbursing the Corporation's pro-rata share of profits. The Corporation formally appealed the DEC's ruling, and, if successful, will require the non-consent penalty withheld by the operator to be disbursed to the Corporation. As a result, there is no anticipated effect on the Corporation's established working interest. As a non-operator, the Corporation is not liable to make any non-consent payments

Due to this contingency, there were no amounts initially recorded on the Company's financial statements prior to payout. In the case where payout has occurred, the Company recorded its share of costs and revenues on a prospective basis beginning with the month that each well had been determined to have achieved payout. As at September 30, 2009, the Corporation was classified as an integrated non-participating owner in 7 gross (0.10 net) wells, including 3 gross (0.06 net) for which the non-consent penalty had been paid out. As of September 30, 2009, Epsilon had received a favorable decision on its F Andrews well appeal from the NY DEC commissioner. The decision was not appealed by Fortuna Energy Inc. and Epsilon is currently awaiting final settlement numbers. This decision will result in reimbursement of the non-consent penalty charged to Epsilon for that well. There has been no decision issued for the remaining wells that Epsilon has appealed.

#### ***Arbitration – Pinpoint Drilling and Directional Services LLC***

On November 5, 2008, Pinpoint Drilling and Directional Services, LLC ("Pinpoint"), a drilling contractor, served a Notice of Arbitration against the Corporation's contract operator covering drilling services on the Highway 706 project under a drilling contract dated May 16, 2008. In the arbitration, Pinpoint sought recovery of approximately \$2.9 million plus interest in allegedly due and owing invoices. On October 5, 2009, the Corporation agreed to settle its dispute with Pinpoint for \$1,075. The Corporation paid the agreed upon amount to Pinpoint on October 27, 2009.

The Corporation's future commitments are summarized in the following table:

	<b>Payments Due by Period</b>			
	<b>Total</b>	<b>Less than 1 Year</b>	<b>1 – 3 Years</b>	<b>4 Years and After</b>
<b>Future Commitments:</b>				
Accounts payable and accrued liabilities.....	\$ 9,968	\$ 9,968	\$ -	\$ -
Line of credit.....	7,500	7,500	-	-
Long-term debt.....	40	23	17	-
Operating leases.....	1,542	605	824	113
Purchase obligations.....	3,453	3,453	-	-
Other long-term obligations <sup>(1)</sup> .....	29,319	-	29,319	-
<b>Total .....</b>	<b>\$ 51,822</b>	<b>\$21,549</b>	<b>\$ 30,160</b>	<b>\$ 113</b>

Notes:

- (1) Includes \$25,500 pertaining to a three year work commitment for Block 55 in Oman and \$3,819 of costs pertaining to the Production Sharing Agreement in Ethiopia.

## **Risk Management**

The Corporation, as part of its operations, enters into agreements which include financial instruments. The Corporation does not utilize derivative instruments to manage various types of risks. The Corporation is exposed to the following risks related to financial assets and liabilities:

### ***Liquidity Risk***

Liquidity risk is the risk that the Corporation will not be able to meet its financial obligations as they become due. Liquidity describes a Corporation's ability to access cash. Companies operating in the upstream oil and natural gas industry require sufficient cash in order to fund capital programs necessary to explore, develop and produce oil and natural gas, and to repay debt. The Corporation actively monitors its cash requirements to ensure it has sufficient available funds to meet current and foreseeable financial requirements at a reasonable cost. The Corporation prepares annual capital expenditure budgets, which are regularly monitored and updated as warranted. The Corporation also utilizes authorizations for expenditures to further manage capital expenditures.

In addition, the Corporation has commitments under existing agreements as described in "Commitments and Contingencies". Given the Corporation's working capital position inclusive of restrictive cash and its outlook on future capital requirements, management assesses liquidity risk to be moderately high.

### ***Commodity Price Risk***

The Corporation sells its current oil and natural gas production primarily at market rates and occasionally via forward fixed price sale contracts. Fluctuations in oil and natural gas prices can materially impact the current and future profitability of the Corporation.

### ***Interest Rate Risk***

The Corporation maintains its short-term deposits in instruments that are redeemable within three months without penalty, and thereby is exposed to interest rate fluctuations. The Corporation does not utilize any interest rate based derivatives. The Corporation analyzes interest rate risk by calculating the effect of percent changes in the interest earned on its cash, cash equivalents and restricted cash. For example, at September 30, 2009, the Corporation had \$7,500 of variable interest rate debt and a 1% plus or minus change in the average annual interest rate would have resulted in a change of \$75 in annual interest costs.

### ***Foreign Currency Risk***

The Corporation is exposed to risks arising from fluctuations in foreign currency exchange rates, primarily between Canadian and U.S. dollars. The Corporation does not utilize any foreign currency based derivatives. In order to manage this risk and to defer the realization of any resulting currency loss from converting Canadian dollars to US dollars, the Corporation retains cash balances in both US and Canadian dollars. Additionally the Corporation has loan facilities in US Dollars totaling \$26,000 in place. At September 30, 2009, the outstanding balance of such loan facilities was \$7,500. During June 2009, the Corporation received a net amount of \$12,932 from the sale of its oil and natural gas property interests in West Virginia and used part of the proceeds to eliminate its line of credit at TD Bank which was secured by Canadian dollars.

The Corporation regularly analyzes foreign currency risk between Canadian dollars and US dollars by calculating the effect of percent changes in the foreign currency exchange rates against period end cash, cash equivalents and restricted cash balances. For example, applying a 5% plus or minus change in the conversion rate (1.0856) of Canadian to US dollars against the Corporation's Canadian denominated cash, cash equivalents and restricted cash balances at September 30, 2009 would have affected the value of such balances by approximately \$660. Substantially all of the Corporation's business operations are conducted in either US dollars or Canadian dollars. The Corporation conducts a negligible amount of business utilizing Yemeni, Oman and Ethiopian currencies and the impact on changes in currency is not significant.

### ***Credit Risk***

Credit risk arises from the possibility that the entities which the Corporation has receivables from or has invested in may experience difficulties and be unable to fulfill their obligations. The Corporation mitigates this risk of credit loss by taking a security interest in underlying assets of the investment. Accounts receivable are assessed on a regular basis by management to ensure the credit worthiness of debtors and the ultimate collection thereof. The Corporation's accounts receivable balances consist of receivables pertaining to its natural gas and oil production in New York and for pro-rata share of costs of operations from its joint interest partners in New York and Yemen, all of which individually may comprise in excess of 10% of the Corporation's overall accounts receivable balances. The Corporation's maximum credit exposure is approximately two months of oil and natural gas production for revenue receivables. The Corporation has the right to offset the amount owed by its joint interest partners against any revenue it disburses to them. As at September 30, 2009 and December 31, 2008, there are no provisions for doubtful accounts pertaining to accounts receivable balances for its oil and natural gas revenues or its joint interest partners. The maximum credit risk that the Corporation is exposed to is the current carrying value of its accounts receivable.

### ***Fair Value***

The Corporation's carrying value of cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities, line of credit, and notes payable equal their fair value due to the immediate or short-term maturity of these instruments.

## **Environmental Issues**

### ***Compliance with Environmental and Safety Regulations***

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills and releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liabilities, and potentially increased capital expenditures and operating

costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it is in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Corporation's financial condition, results of operations or prospects. The Corporation must also conduct its operations in accordance with various laws and regulations concerning occupational safety and health. Currently, the Corporation does not foresee expending material amounts to comply with occupational safety and health laws and regulations. However, since such laws and regulations are frequently changed, the Corporation is unable to predict the future effect of these laws and regulations.

### ***Middle East and Africa***

In emerging nations, such as Yemen, Oman and Ethiopia, where environmental regulations and legislation are evolving, many oil and natural gas exploration and production companies operate in accordance with standards prevailing in established oil and natural gas producing jurisdictions, such as Canada and the United States. The Corporation has yet to conduct any significant on the ground operations in Ethiopia, but intends to adhere to established industry practice standards upon the commencement of such operations.

The Corporation's activities in the Middle East and Africa are in predominately arid desert areas. As such, the environmental impact associated with exploration and production activity in these areas are significantly less than is typical for similar oil and natural gas exploration, development and production activities located in more temperate or tropical environments. The Corporation is committed to conducting its operations in the Middle East and Africa in accordance with environmental standards used by other major international oil and natural gas exploration and production companies. Generally, such standards meet or exceed those imposed by legislation and regulations in Yemen, Oman and Ethiopia.

### ***North America***

The Corporation's activities are subject to numerous federal, provincial and state laws and regulations concerning the storage, use and discharge of materials into the environment, the remediation of environmental impacts and other matters relating to environmental protection, all of which may adversely affect the Corporation's operations and the costs of doing business. Federal, provincial and state regulatory authorities also have established rules and regulations requiring permits for drilling, drilling bonds and reports concerning drilling and producing activities. Such regulations also cover the location of wells, the method of drilling and casing wells, the surface use and restoration of well locations, the plugging and abandoning of wells, and other matters. There can be no assurance that future legislation or administrative regulations or interpretations will not impose stricter requirements that could have an adverse impact on the operating costs of the Corporation and the oil and natural gas industry in general. The Corporation believes it is in material compliance with existing environmental laws and regulations and does not currently believe that it will be required to expend material amounts to comply with existing environmental laws and regulations in the future.

### **Related Party Transactions**

The Corporation reports its related party transactions on an exchange amount basis in equivalent US dollars. A summary of such transactions follows:

#### ***Executive Chairman***

The Corporation utilizes administrative services provided by 706147 Ontario, Inc., a company owned by the Executive Chairman's spouse. Administrative service expenses for the nine months ended September 30, 2009 and year ended December 31, 2009 were \$39 and \$57, respectively. In addition, the Corporation shares office space with Capital Z Corporation, a company owned by the Executive Chairman, at no charge.

**Director**

On February 7, 2007, the Corporation obtained a 25% undivided participating interest in Gastem Inc.'s undeveloped oil and natural gas interests covering approximately 1,184,000 acres (249,000 net) in the St. Lawrence Lowlands and in the Gaspé Peninsula of Quebec. Under terms of the agreement, the Corporation may elect to participate on a well-by-well basis with a 25% working interest in any current or future oil and natural gas property Gastem Inc. may acquire in Quebec. In return, the Corporation granted Gastem Inc. the right to participate for 25% of the Corporation's interest in certain future wells to be drilled in the Corporation's Amber Bank project in West Virginia by spending up to \$1.05 million. The Corporation's carrying value of the portion of its Amber Bank project's leasehold attributable to Gastem Inc.'s participation was nominal. The agreement was consummated with the expectation that Raymond Savoie, Gastem Inc.'s President would become a director of the Corporation. Mr. Savoie became a director of the Corporation on July 16, 2007. On June 16, 2009, the Corporation, along with Gastem Inc., sold all of its oil and natural gas property interests in West Virginia to an unrelated third party for a gross amount of \$14,000 (\$780 net to Gastem Inc.). Related party transactions with Gastem Inc. were conducted in US dollars. A summary of Gastem's joint venture share of related party transactions between the Corporation and Gastem Inc. follows:

	<b>Nine Months Ended September 30, 2009</b>	<b>Year Ended December 31, 2008</b>
<b>Gastem Inc.:</b>		
Accounts receivable.....	\$ -	\$ -
Joint venture costs.....	32	77
Joint venture revenues.....	112	310
Accounts payable.....	-	15
Proceeds from sale of assets.....	\$ 780	\$ -

**Director and former President and CEO**

Austin Exploration LLC, a company owned by a Director who is also the former President and CEO of the Corporation, is also a participant in the Corporation's Empire project. Western Land Services Inc., a company owned by the same person, provides oil and natural gas lease brokerage services to the Corporation in accordance with a Project Services Agreement between Western Land Services and the Corporation. Under terms of the Project Services Agreement, Western Land Services agreed to provide services to the Corporation at its lowest corporate rates less 10%. Substantially all of the service amounts provided by Western Land Services are capitalized with oil and natural gas properties. Related party transactions with the Director and former President and CEO were conducted in US dollars. A summary of related party transactions between the Corporation and its Director who is also the former President and CEO follows:

	<b>Nine Months Ended September 30, 2009</b>	<b>Year Ended December 31, 2008</b>
<b>Austin Exploration LLC:</b>		
Accounts receivable.....	\$ 5	\$ 110
Joint venture costs.....	288	2,655
Joint venture revenues.....	466	902
Accounts payable.....	\$ -	\$ 75
<b>Western Land Services:</b>		
Lease brokerage services.....	\$ 337	\$ 1,668
Accounts payable.....	\$ 28	\$ 139