

**GALLEON ENERGY INC.**

**Management's Discussion and Analysis**

**September 30, 2010**

## **Management's Discussion and Analysis**

This Management's Discussion & Analysis ("MD&A") is intended to assist in the understanding of the trends and significant changes in the financial condition and results of operations of Galleon Energy Inc. ("Galleon" or the "Corporation") for the three and nine month periods ended September 30, 2010 with comparisons to the three and nine months ended September 30, 2009 and as at December 31, 2009. The MD&A has been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP") and should be read in conjunction with the unaudited interim financial statements as at and for the three and nine month periods ended September 30, 2010 and 2009 and the audited financial statements and MD&A for the year ended December 31, 2009.

Petroleum and natural gas reserves and volumes are converted to a common unit of measure on a basis of six thousand cubic feet (Mcf) of gas to one barrel (Bbl) of oil. BOEs may be misleading, particularly if used in isolation. The forgoing conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Amounts are shown in Canadian dollars unless otherwise stated. All production volumes disclosed herein are sales volumes.

This MD&A is based on information available as of, and is dated, November 11, 2010.

## **Non-GAAP Measurements**

The MD&A contains terms commonly used in the oil and gas industry, such as funds from operations, funds from operations per share, and operating netback. These terms are not defined by GAAP and should not be considered an alternative to, or more meaningful than, cash provided by operating activities or net earnings as determined in accordance with Canadian GAAP as an indicator of Galleon's performance. Management believes that in addition to net earnings, funds from operations is a useful financial measurement which assists in demonstrating the Corporation's ability to fund capital expenditures necessary for future growth or to repay debt. Galleon's determination of funds from operations may not be comparable to that reported by other companies. All references to funds from operations throughout this report are based on cash flow from operating activities before changes in non-cash working capital and abandonment expenditures. The Corporation calculates funds from operations per share by dividing funds from operations by the weighted average number of Class A shares outstanding.

Galleon uses the term net debt in the MD&A and presents a table showing how it has been determined. This measure does not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures presented by other companies.

## **Forward-Looking Statements**

Statements that are not historical facts may be considered forward looking statements including management's assessment of future plans and operations, development plans, drilling plans and the timing thereof, goals and plans to increase proven producing reserves by drilling existing drilling inventory, plans to farmout certain lands, timing of facilities expansion and the effect thereof, the effect of certain regulatory applications, plans to develop certain areas to operate at maximum facility capacity, capital expenditures, the nature of the expenditures and timing thereof and the method of funding thereof, expectation as to the volatility of commodity prices and plans and timing related to the adoption of IFRS and certain anticipated effects thereof. These forward-looking statements sometimes include words to the effect that management believes or expects a stated condition or result. All estimates and statements that describe the Corporation's objectives, goals or future plans are forward-looking statements. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets,

volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources. As a consequence, Galleon's actual results may differ materially from those expressed in, or implied by, the forward-looking statements.

Forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although the Corporation believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because the Corporation can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which the Corporation operates; the timely receipt of any required regulatory approvals; the ability of the Corporation to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Corporation has an interest in to operate the field in a safe, efficient and effective manor; the ability of the Corporation to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Corporation to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Corporation operates; and the ability of the Corporation to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors and assumptions is not exhaustive. Additional information on these and other factors that could affect Galleon's operations and financial results are included elsewhere herein and in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website ([www.sedar.com](http://www.sedar.com)), or at Galleon's website ([www.galleonenergy.com](http://www.galleonenergy.com)). Furthermore, the forward-looking statements contained herein are made as at the date hereof and Galleon does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

## FINANCIAL AND OPERATING HIGHLIGHTS

	Three months ended		Nine months ended	
	September 30		September 30	
<i>(\$000s except per share and per unit amounts)</i>	2010	2009	2010	2009
<b>Financial</b>				
Revenue before royalties and financial derivatives	44,279	49,497	161,836	156,857
Funds flow from operations <sup>1</sup>	20,425	18,818	79,251	74,573
Per share – basic	0.24	0.23	0.93	0.96
Per share – diluted	0.24	0.23	0.93	0.96
Net income (loss)	(5,621)	(1,815)	9,198	(28,918)
Per share – basic	(0.07)	(0.02)	0.11	(0.37)
Per share – diluted	(0.07)	(0.02)	0.11	(0.37)
Capital expenditures – exploration & development	40,746	30,035	102,409	80,045
Total assets	1,026,875	1,127,665	1,026,875	1,127,665
Net debt <sup>1,2</sup>	139,732	242,056	139,732	242,056
Shareholders' equity	717,196	701,054	717,196	701,054
Weighted average shares outstanding				
Basic	84,869,236	82,890,883	85,036,467	78,082,486
Diluted	84,869,236	82,890,883	85,048,031	78,082,486
<b>Operating</b>				
Average daily production				
Light oil (Bbl/d)	2,517	3,872	3,018	4,112
Heavy oil (Bbl/d)	1,009	1,281	1,092	1,235
NGLs (Bbl/d)	433	561	499	604
Natural gas (Mcf/d)	59,186	57,012	63,662	62,746
Total (BOE/d)	13,823	15,216	15,219	16,409
Average selling prices <sup>3</sup>				
Light oil (\$/Bbl)	71.26	67.12	73.94	58.27
Heavy oil (\$/Bbl)	58.13	57.27	60.42	47.68
NGLs (\$/Bbl)	49.48	43.87	53.40	38.75
Natural gas (\$/Mcf)	3.75	3.16	4.35	4.03
Total (\$/BOE)	34.82	35.36	38.95	35.01

<sup>1</sup> See "Non-GAAP Measurements"

<sup>2</sup> Net debt includes bank indebtedness, working capital and capital leases, but excludes financial derivatives

<sup>3</sup> The average prices reported are before realized derivatives and transportation charges

## Results of Operations

Comparative financial results for the quarter are as follows:

Three months ended September 30	2010		2009	
	1,271,739 BOE		1,399,847 BOE	
(\$000s)		\$/BOE		\$/BOE
Revenues	44,279	34.82	49,497	35.36
Realized gain on financial derivatives	2,420	1.90	699	0.50
Other income	-	-	6	-
Royalties	(8,293)	(6.52)	(13,489)	(9.64)
GCA <sup>1</sup>	3,013	2.36	3,549	2.54
Transportation costs	(2,110)	(1.66)	(1,970)	(1.41)
Operating costs	(12,978)	(10.20)	(13,045)	(9.32)
<b>Net</b>	<b>26,331</b>	<b>20.70</b>	<b>25,247</b>	<b>18.03</b>
G&A	(3,930)	(3.09)	(3,453)	(2.47)
Restructuring costs	(59)	(0.05)	-	-
Interest costs	(1,849)	(1.45)	(2,876)	(2.05)
Capital and other taxes	(68)	(0.05)	(100)	(0.07)
<b>Funds from operations<sup>2</sup></b>	<b>20,425</b>	<b>16.06</b>	<b>18,818</b>	<b>13.44</b>

Nine months ended September 30	2010		2009	
	4,154,746 BOE		4,479,748 BOE	
(\$000s)		\$/BOE		\$/BOE
Revenues	161,836	38.95	156,857	35.01
Realized gain on financial derivatives	9,184	2.21	8,810	1.97
Other income	-	-	752	0.17
Royalties	(35,505)	(8.54)	(40,626)	(9.07)
GCA <sup>1</sup>	9,628	2.32	17,251	3.85
Transportation costs	(6,721)	(1.62)	(6,368)	(1.42)
Operating costs	(38,793)	(9.34)	(44,132)	(9.85)
<b>Net</b>	<b>99,629</b>	<b>23.98</b>	<b>92,544</b>	<b>20.66</b>
G&A	(10,561)	(2.54)	(11,481)	(2.56)
Restructuring costs	(1,242)	(0.30)	-	-
Interest costs	(8,441)	(2.03)	(6,163)	(1.38)
Capital and other taxes	(134)	(0.04)	(327)	(0.07)
<b>Funds from operations<sup>2</sup></b>	<b>79,251</b>	<b>19.07</b>	<b>74,573</b>	<b>16.65</b>

<sup>1</sup> GCA means Gas Cost Allowance

<sup>2</sup> See "Non-GAAP Measurements"

## Petroleum and Natural Gas Revenues

Three months ended September 30	2010		2009	
(\$000s)		%		%
Light oil	16,417	37	23,884	48
Heavy oil	5,397	12	6,733	14
NGLs	1,971	5	2,266	4
Natural gas	20,427	46	16,654	34
Royalty income	67	-	(40)	-
<b>Total</b>	<b>44,279</b>	<b>100</b>	<b>49,497</b>	<b>100</b>

Nine months ended September 30	2010		2009	
(\$000s)		%		%
Light oil	60,668	38	65,272	42
Heavy oil	18,016	11	16,049	10
NGLs	7,275	4	6,387	4
Natural gas	75,503	47	68,859	44
Royalty income	374	-	290	-
<b>Total</b>	<b>161,836</b>	<b>100</b>	<b>156,857</b>	<b>100</b>

Revenues for the three months ended September 30, 2010 decreased by 11%, to \$44.3 million from \$49.5 million for the same period in 2009. Gas revenues increased in Q3 2010 due to increases in both production volumes and natural gas prices. The increase in oil prices during the third quarter of 2010 was more than offset by a decrease in production volumes resulting from the sale of properties, primarily the Puskwa light oil properties sold in Q2 2010.

## Production

	Three months ended September 30				Nine months ended September 30			
	2010		2009		2010		2009	
Light oil (Bbls/d)	2,517	18	3,872	26	3,018	20	4,112	25
Heavy oil (Bbls/d)	1,009	7	1,281	8	1,092	7	1,235	8
NGLs (Bbls/d)	433	3	561	4	499	3	604	3
Natural gas (Mcf/d)	59,186	72	57,012	62	63,662	70	62,746	64
<b>BOE/d (6:1)</b>	<b>13,823</b>	<b>100</b>	<b>15,216</b>	<b>100</b>	<b>15,219</b>	<b>100</b>	<b>16,409</b>	<b>100</b>

Average production was 13,823 BOE/d for the third quarter of 2010, 9% lower than the average production of 15,216 BOE/d for the third quarter of 2009. Daily production volumes varied by product as follows: light oil decreased by 35%; heavy oil decreased by 21%; natural gas liquids decreased by 23% and natural gas increased by 4%.

After excluding properties which were sold prior to Q3 2010, average production for the three months ended September 30, 2010 was 6% higher than the average production recorded in Q3 2009.

## Commodity Pricing and Marketing

Petroleum products are sold to major Canadian marketers at spot reference prices or prices subject to commodity contracts based on US WTI for crude oil and AECO for natural gas. As a means of managing the risk of commodity price volatility, Galleon has entered into several natural gas and crude oil financial contracts.

The Corporation has the following financial contracts in place as at September 30, 2010:

Natural Gas:		
January 1, 2010 - December 31, 2011	5,000 GJ/d	CDN \$5.85/GJ
January 1, 2010 - December 31, 2011	5,000 GJ/d	CDN \$5.75/GJ
April 1, 2010 - March 31, 2011	5,000 GJ/d	CDN \$5.76/GJ
January 1, 2011 - December 31, 2011	20,000 GJ/d	CDN \$5.20/GJ
Crude Oil:		
Fixed Price:		
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN \$74.30/Bbl
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN \$76.50/Bbl
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN \$74.50/Bbl
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN \$77.00/Bbl
January 1, 2011 – December 31, 2011	500 Bbl/d	WTI CDN \$92.00/Bbl
January 1, 2011 – December 31, 2011	1,000 Bbl/d	WTI CDN \$84.15/Bbl
Costless Collars:		
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN \$75.00-\$94.00/Bbl
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN \$75.00-\$95.00/Bbl
January 1, 2011 – December 31, 2011	1,000 Bbl/d	WTI CDN \$77.10-\$90.00/Bbl
Other:		
January 1, 2012 – December 31, 2012	1,000 Bbl/d	WTI US \$85.00 Call
January 1, 2012 – December 31, 2012	1,100 Bbl/d	WTI US\$ 85.00 Swaption
Interest Rate Swap:		
Notional Amount CAD \$100 million	Term: January 20, 2009 – January 20, 2011	
Fixed rate 1.1% - Floating rate is reset against CAD--CDOR on each 3 month anniversary		

In the third quarter of 2010, Galleon recorded realized gains of \$2.4 million on these financial contracts, compared to a \$0.7 million gain realized in the third quarter of 2009.

Based on the mark to market value at September 30, 2010, an unrealized gain on financial contracts of \$0.4 million was recorded in the third quarter of 2010, compared to an unrealized gain of \$13.3 million in Q3 2009.

Subsequent to September 30, 2010, the Corporation entered into the following financial contracts:

Natural Gas:		
April 1, 2011 - December 31, 2011	5,000 GJ/d	CDN \$5.60/GJ
Crude Oil:		
January 1, 2012 – December 31, 2012	527 Bbl/d	WTI US\$85.00/Bbl Call

*Prices – prior to realized gains or losses on financial contracts and prior to transportation*

	Three months ended		Nine months ended	
	September 30		September 30	
	2010	2009	2010	2009
Light oil (\$/Bbl)	71.26	67.12	73.94	58.27
Heavy oil (\$/Bbl)	58.13	57.27	60.42	47.68
NGLs (\$/Bbl)	49.48	43.87	53.40	38.75
Natural gas (\$/Mcf)	3.75	3.16	4.35	4.03

Comparing the three month period ending September 30, 2010 to 2009, the light oil price increased by 6%, the heavy oil price increased by 2%, the NGL price increased by 13%, and the natural gas price increased by 19%.

*Crude Oil Prices*

Three months ended September 30	2010		2009	
	\$000s	\$/Bbl	\$000s	\$/Bbl
Crude oil	21,898	67.50	30,655	64.67
Realized financial contracts	(661)	(2.04)	(2,220)	(4.68)
Transportation	(491)	(1.51)	(478)	(1.01)
Net crude oil	20,746	63.95	27,957	58.98

Nine months ended September 30	2010		2009	
	\$000s	\$/Bbl	\$000s	\$/Bbl
Crude oil	78,911	70.33	81,496	55.82
Realized financial contracts	(1,846)	(1.65)	(2,742)	(1.88)
Transportation	(1,433)	(1.28)	(1,579)	(1.08)
Net crude oil	75,632	67.40	77,175	52.86

*Natural Gas Prices*

Three months ended September 30	2010		2009	
	\$000s	\$/Mcf	\$000s	\$/Mcf
Natural gas	20,410	3.75	16,576	3.16
Realized financial contracts	3,119	0.57	3,074	0.59
Transportation	(1,615)	(0.30)	(1,413)	(0.27)
Net natural gas	21,914	4.02	18,237	3.48

Nine months ended September 30	2010		2009	
	\$000s	\$/Mcf	\$000s	\$/Mcf
Natural gas	75,650	4.35	68,974	4.03
Realized financial contracts	11,345	0.65	11,794	0.69
Transportation	(5,283)	(0.30)	(4,710)	(0.27)
Net natural gas	81,712	4.70	76,058	4.45

## Performance by Property

Three months ended September 30							
	2010			2009			2010
	Production		Operating netbacks/ BOE <sup>1</sup>	Production		Operating netbacks/ BOE <sup>1</sup>	Funds from operations <sup>2</sup>
	BOE/d	%	\$	BOE/d	%	\$	%
Eastern Montney	5,524	40	20.93	4,565	30	13.91	51
Kakut	3,890	28	16.63	3,150	21	14.72	29
North Peace River Arch	4,409	32	9.99	5,283	35	8.82	20
Sold properties	-	-	-	2,218	14	31.88	-
	<b>13,823</b>	<b>100</b>	<b>16.26</b>	<b>15,216</b>	<b>100</b>	<b>14.93</b>	<b>100</b>

Nine months ended September 30							
	2010			2009			2010
	Production		Operating netbacks/ BOE <sup>1</sup>	Production		Operating netbacks/ BOE <sup>1</sup>	Funds from operations <sup>2</sup>
	BOE/d	%	\$	BOE/d	%	\$	%
Eastern Montney	5,459	36	19.93	5,011	31	14.13	37
Kakut	4,233	28	19.14	3,278	20	13.45	28
North Peace River Arch	4,550	30	15.12	5,658	34	10.32	23
Sold properties	977	6	36.98	2,462	15	27.33	12
	<b>15,219</b>	<b>100</b>	<b>19.37</b>	<b>16,409</b>	<b>100</b>	<b>14.67</b>	<b>100</b>

<sup>1</sup> Operating netbacks/BOE exclude GCA and hedging gains and losses, and are calculated by subtracting royalties and operating costs from revenues.

<sup>2</sup> See "Non-GAAP Measurements".

The Corporation has been structured into three business units: Eastern Montney, North Peace River Arch and Kakut. These business units, and the general nature of the activities planned within each, are described as follows:

### Eastern Montney Business Unit – Comprised of Eastern Montney Gas/Oil and Culp/McLeans Creek Light Oil

Eastern Montney production averaged 5,524 BOE/d (70% natural gas and 30% oil and NGLs) during Q3 2010, which was 21% higher than the average production during Q3 2009. The Eastern Montney natural gas project continues to represent a significant resource to Galleon and is the largest producing area, contributing 51% to total funds from operating activities in Q3 2010 based on 40% of production volumes.

Galleon has been developing the Eastern Montney project for over five years. Horizontal development began more than two years ago. To the end of Q3-2010, Galleon has drilled a total of 57 horizontal wells and 83 vertical wells in the project area. The project area encompasses a fairway extending 30 miles long by 10 miles wide that has been mapped and tested. The current strategy is to increase proved producing reserves by drilling the large inventory of undeveloped locations. Given current gas prices, Galleon plans to drill just enough wells into the Montney gas project to utilize the capacity that exists in its gas plant.

A total of 4 (3.9 net) Eastern Montney horizontal gas wells, and 2 (2.0 net) additional oil wells were drilled within this business unit during Q3 2010.

**Kakut Business Unit – Comprised of Kakut, Senex/Sawn Lake and Edam, Sask.**

The Kakut property continues to be a significant growth area for Galleon. Production for Q3 2010 averaged 3,890 BOE/d (74% natural gas and 26% oil and NGLs) which represents an increase of 23% from Q3 2009. The Kakut property contributed 29% of total funds from operating activities based on 28% of production volumes in Q3 2010.

The Kakut Doig light oil/natural gas play is a regional resource that is defined by over 40 vertical wells and occurs at a relatively shallow depth of 1,550 metres. Drilling has confirmed a productive fairway of at least 15 miles in length.

Galleon completed the Kakut battery expansion in late August, 2010, in anticipation of continued growth in both oil and gas production. The expansion has increased fluid handling capacity from 1,000 to 10,000 barrels per day. Galleon's Kakut gas plant capacity is 28 Mmcf/d.

To the end of the third quarter, Galleon had drilled 19 Doig horizontal wells at Kakut. The Company plans to continue drilling on this project at a measured pace, and to continue to closely monitor results. This project is in its early-stages and long-term well-performance expectations will be refined over time.

After June 30, 2010, two wells, 04-28-74-03W6 and 16-06-75-03W6 (both 100% working interest), which were producing a total of approximately 900 BOE/d (83% natural gas and 17% oil and NGLs) were shut in due to high gas-oil ratios (GOR's), after their four month new oil well production period (NOWPP) came to an end. Galleon has submitted applications to the ERCB for these two wells, which, if granted, would result in the two wells being placed back on production at optimal rates.

During the third quarter, Galleon received approval for the remaining Kakut Doig holding applications outstanding. This brings the total to 11 sections which are approved for 4 horizontal wells per section.

**North Peace River Arch Business Unit ("NPRA") – Comprised of various properties, including Eaglesham, Whitelaw, Flood, Dixonville, Alexis/St. Anne, and N.E. BC**

Production at NPRA in Q3 2010 averaged 4,409 BOE/d (71% natural gas and 29% oil and NGLs), a decrease of 17% from Q3 2009. In Q3 2010, NPRA contributed 20% of the funds from operations and 32% of production volumes.

In this business unit, Galleon has various new projects primarily targeting light oil. The Company has also identified natural gas opportunities here, which will be pursued as priorities warrant. In general, horizontal drilling technology will be used to develop these opportunities. Much of the Company's activity here will target Montney oil plays that are analogous to the Grimshaw Triassic D pool which has seen substantial horizontal drilling activity over the past year. Large oil-in-place assets at Alexis/St. Anne will also continue to be exploited and optimized.

In Q3 2010, Galleon drilled 1 (0.7 net) Montney horizontal oil well, and 1 (0.8 net) vertical gas well in the NPRA area.

## Royalties

<b>Three months ended September 30</b>	<b>2010</b>	<b>2009</b>
(\$000s, except as indicated)		
Crown	6,478	11,710
Freehold	996	709
GORR and other	819	1,070
<b>Gross royalties</b>	<b>8,293</b>	<b>13,489</b>
GCA	(3,013)	(3,549)
<b>Net royalties</b>	<b>5,280</b>	<b>9,940</b>
% of revenue	<b>18.7</b>	<b>27.3</b>
% of revenue net of GCA	<b>11.9</b>	<b>20.1</b>
<b>Nine months ended September 30</b>	<b>2010</b>	<b>2009</b>
(\$000s, except as indicated)		
Crown	28,994	35,313
Freehold	3,397	1,958
GORR and other	3,114	3,355
<b>Gross royalties</b>	<b>35,505</b>	<b>40,626</b>
GCA	(9,628)	(17,251)
<b>Net royalties</b>	<b>25,877</b>	<b>23,375</b>
% of revenue	<b>21.9</b>	<b>25.9</b>
% of revenue net of GCA	<b>16.0</b>	<b>14.9</b>

Gross royalties were 18.7% for the third quarter of 2010, compared to 27.3% for the same period in 2009. By product the gross royalty rates were 22.9% for heavy oil, 15.7% for light oil, 19.0% for natural gas and 30.3% for liquids for Q3 2010. For the third quarter of 2009, the royalty rates were 21.4% for heavy oil, 30.2% for light oil, 22.4% for natural gas and 34.0% for liquids.

Net royalties were 11.9% for the third quarter of 2010 compared to 20.1% for the same period in 2009.

The gross royalty rate for light oil decreased in Q3 2010, compared to Q3 2009, reflecting the sale of higher royalty rate properties and royalty rate reductions applicable to production from new wells.

Under the Drilling Royalty Credit (“DRC”) incentive program, the Alberta Government will apply up to \$200 per metre for wells spud during the period April 1, 2009 to March 31, 2011 against net Crown royalties payable. As at September 30, 2010, the Corporation had recorded drilling credits of \$18.9 million as a reduction of property and equipment.

## Operating Costs

### Three months ended September 30

	2010			2009		
	Production	Operating Costs		Production	Operating Costs	
	%	%	\$/BOE	%	%	\$/BOE
Eastern Montney	40	34	8.75	30	28	8.75
Kakut	28	21	7.68	21	17	7.58
North Peace River Arch	32	45	14.23	35	45	12.16
Sold properties	-	-	-	14	10	6.19
	<b>100</b>	<b>100</b>	<b>10.20</b>	<b>100</b>	<b>100</b>	<b>9.32</b>

### Nine months ended September 30

	2010			2009		
	Production	Operating Costs		Production	Operating Costs	
	%	%	\$/BOE	%	%	\$/BOE
Eastern Montney	36	35	9.02	31	31	9.87
Kakut	28	22	7.55	20	17	8.76
North Peace River Arch	30	39	12.24	34	42	11.93
Sold properties	6	4	5.31	15	10	6.48
	<b>100</b>	<b>100</b>	<b>9.34</b>	<b>100</b>	<b>100</b>	<b>9.85</b>

Operating costs were \$10.20/BOE for the third quarter of 2010, an increase of 9% from \$9.32/BOE for the same period of the prior year, influenced in part by the sale of Puskwa which was a lower operating cost property. Approximately \$0.30/BOE of this increase relates to a one-time turnaround cost incurred in Q3 2010 at Donnelly and Eaglesham.

In the Eastern Montney natural gas project, quarterly operating costs were consistent year over year at \$8.75/BOE.

Operating costs at Kakut were \$7.68/BOE in Q3 2010, an increase of 1% from \$7.58/BOE in the same period of the prior year.

Operating costs at NPRA were \$14.23/BOE in third quarter 2010, compared to \$12.16/BOE in the same period of 2009. The 17% increase in operating costs per BOE was a function of lower production volumes.

## General and Administration Expenses

### Three months ended September 30

	2010		2009	
		\$/BOE		\$/BOE
(\$000s)				
Gross	5,323	4.18	4,645	3.32
Capitalized overhead	(1,021)	(0.80)	(784)	(0.56)
Overhead recoveries	(372)	(0.29)	(408)	(0.29)
	<b>3,930</b>	<b>3.09</b>	<b>3,453</b>	<b>2.47</b>

### Nine months ended September 30

	2010		2009	
		\$/BOE		\$/BOE
(\$000s)				
Gross	14,504	3.49	15,136	3.38
Capitalized overhead	(2,515)	(0.61)	(2,238)	(0.50)
Overhead recoveries	(1,428)	(0.34)	(1,417)	(0.32)
	<b>10,561</b>	<b>2.54</b>	<b>11,481</b>	<b>2.56</b>

Gross G&A expenses increased by \$0.7 million or 15% in Q3 2010 from Q3 2009, due primarily to higher employee expenses.

For the three months ended September 30, 2010 G&A expenses by category were: salary and employee – 66%, office – 18%, consulting – 5%, computer – 5%, shareholder costs – 1%, audit, engineering and legal – 3%, and corporate – 2%.

### **Restructuring Costs**

In March 2010 the Board of Directors initiated a process to identify and consider strategic alternatives, with a view to enhancing shareholder value. The strategic review process was completed in July 2010. To increase balance sheet strength to give the Corporation the flexibility to execute the operational plan, assets in the Puskwa area of Alberta were sold for cash consideration, net of adjustments, of \$131.5 million in the second quarter of 2010. In conjunction with the asset sale, Galleon restructured its technical and operational teams. Expenses of \$1.2 million related to the restructuring process were incurred in the nine months ended September 30, 2010.

### **Interest**

Interest expense of \$1.8 million for the three months ended September 30, 2010 was 36% lower than the \$2.9 million recorded in the same period of the prior year. A lower average debt balance outstanding during Q3 2010, resulting from the application of proceeds received on the sale of the Puskwa assets, more than offset the increase in the effective interest rate.

At September 30, 2010 an amount of \$122.3 million was drawn against the Corporation's credit facility, compared to \$217.2 million at September 30, 2009.

### **Stock Based Compensation**

Stock based compensation was a non-cash expense of \$0.2 million for the third quarter of 2010, compared to \$2.5 million recorded in the same quarter of the prior year. As a result of forfeitures of unvested options in Q3 2010, previously recorded stock based compensation expense of \$1.1 million was reversed.

During the three months ended September 30, 2010, 300,000 stock options were granted to employees with an exercise price of \$3.56 per share. At September 30, 2010, 5,783,501 stock options were outstanding at an average exercise price of \$5.95 per share.

### **Depletion, Depreciation and Accretion**

For the three months ended September 30, 2010, depletion and depreciation totaled \$29.5 million (\$23.23/BOE), as compared to \$30.6 million (\$21.86/BOE) for the same period in the prior year. Reserve additions for the quarter were estimated internally.

Capital expenditures of \$58.4 million (September 30, 2009 - \$100.1 million) related to undeveloped land and seismic have been excluded from the depletion and depreciation calculation, and \$147.0 million (September 30, 2009 - \$177.2 million) of future development costs have been added.

Accretion expense on the Corporation's asset retirement obligation was \$712,000 for the third quarter of 2010, compared to \$664,000 in the third quarter of 2009.

## Capital and Future Taxes

The current tax expense of \$68,000 (September 30, 2009 - \$100,000) was related to Saskatchewan capital and resource tax, and was based upon revenues earned in Saskatchewan. It is not expected that Galleon will pay income taxes in 2010.

An income tax recovery of \$4.0 million was recorded in Q3 2010 on a loss before tax of \$9.5 million. An income tax expense of \$0.2 million on a loss before tax of \$1.5 million was recorded in 2009. The Q3 2010 income tax provision includes a \$1.9 million benefit arising from a reduction in the expected future tax rate.

## Capital Expenditures

	(\$000s)
Property & equipment balance at December 31, 2009	1,041,140
Additions to property and equipment	102,409
Dispositions of property and equipment	(132,012)
Acquisitions of property and equipment	17,650
Asset retirement obligation additions	568
Asset retirement obligation disposed	(1,839)
Depletion, depreciation and other	(93,071)
<b>Property &amp; equipment balance at September 30, 2010</b>	<b>934,845</b>

Three months ended September 30	2010		2009	
		%		%
(\$000s)		%		%
Land	1,854	5	791	3
Geological and geophysical	660	2	281	1
Drilling and completion	30,369	74	15,974	53
Plant and facilities	7,815	19	12,816	43
Other assets	48	-	11	-
<b>Exploration and development expenditures</b>	<b>40,746</b>	<b>100</b>	<b>29,873</b>	<b>100</b>

Nine months ended September 30	2010		2009	
		%		%
(\$000s)		%		%
Land	6,028	6	2,150	3
Geological and geophysical	1,191	1	1,680	2
Drilling and completion	77,045	75	48,375	61
Plant and facilities	18,066	18	27,554	34
Other assets	79	-	56	-
<b>Exploration and development expenditures</b>	<b>102,409</b>	<b>100</b>	<b>79,815</b>	<b>100</b>

Exploration and development expenditures during Q3 2010 totaled \$40.7 million. Drilling and completion operations accounted for \$30.4 million, equipment and facility expenditures were \$7.8 million and \$2.5 million was spent on land and seismic.

During the third quarter of 2010, the Galleon drilled and cased 17 (16.1 net) wells.

In late August 2010, the Corporation expanded fluid capacity at the Kakut oil battery. This will allow up to 10,000 barrels of fluid per day to be processed at this facility which serves the Kakut Doig light oil project.

The final payment required under the equipment lease financing arrangement was made during the three months ended September 30, 2010.

## Liquidity and Capital Resources

<b>September 30</b>	<b>2010</b>	<b>2009</b>
(\$000s)		
Bank debt	122,283	230,799
Working capital deficiency <sup>1</sup>	17,449	11,257
<b>Total net debt</b>	<b>139,732</b>	<b>242,056</b>

<sup>1</sup> Excludes future income taxes and fair value of financial derivatives

### Funding of Capital Program

<b>Three months ended September 30</b>	<b>2010</b>	<b>2009</b>
(\$000s)		
Issuance (repurchase) of shares, net of costs	(3,544)	(25)
Funds from operations	20,425	18,818
Change in bank debt	10,564	(5,030)
Change in capital leases	(1,135)	(1,313)
Acquisition of properties	(684)	(162)
Disposition of properties	1,100	756
Change in inventory	(309)	2,179
Change in working capital and other	14,329	14,650
	<b>40,746</b>	<b>29,873</b>

<b>Nine months ended September 30</b>	<b>2010</b>	<b>2009</b>
(\$000s)		
Issuance (repurchase) of shares, net of costs	(3,276)	34,922
Funds from operations	79,251	74,573
Change in bank debt	(94,960)	(18,216)
Change in capital leases	(1,545)	(1,719)
Acquisition of properties	(17,650)	(230)
Disposition of properties	132,012	5,389
Change in inventory	(410)	6,599
Change in working capital and other	8,987	(21,503)
	<b>102,409</b>	<b>79,815</b>

The Corporation has \$250 million in credit facilities available consisting of a \$225 million extendible 364 day revolving term facility and a \$25 million non-revolving facility. The \$25 million facility is available subject to mutual approval of the banking syndicate and the Corporation, including repayment terms. Collateral for the facilities consists of a demand debenture for \$500 million collateralized by a first floating charge over all of the property and equipment of the Corporation. At September 30, 2010, an amount of \$122.3 million was drawn against the credit facilities (December 31, 2009 - \$217.2 million).

The facilities bear interest at the bank's prime or banker's acceptance rates plus a rate margin. The margin ranges from 1.5% per annum to 5.5% per annum, based upon the Corporation's debt to cash flow ratio. For the three and six months ended September 30, 2010, the effective interest rates were 6.6% and 6.0%, respectively (September 30, 2009 - 4.8% and 3.3%).

## Commitments

### *Office Lease Payments*

At September 30, 2010 the Corporation has committed to future minimum payments under operating leases that cover office space as follows:

	<u>Amount \$</u>
2010	448
2011	1,793
2012	1,793
2013	1,793
2014	1,793
2015	1,793
Thereafter	2,689

### *Litigation*

The Corporation is involved in various claims and legal actions arising from the normal course of business. The Corporation does not expect that the outcome of these proceedings will have a material adverse effect on the Corporation as a whole.

### *Flow-through Shares*

In connection with the Corporation's flow-through share offering in 2009, Galleon is obligated to spend \$17,160,000 on qualifying exploration expenses prior to December 31, 2010. As at September 30, 2010, \$15.5 million of the required qualifying expenditures had been incurred.

## Financial Instruments

Refer to the "Commodity Pricing and Marketing" section.

## Business Risks

### *General*

Galleon is engaged in the exploration, development and production of crude oil and natural gas. The oil and gas business is inherently risky and there is no assurance that hydrocarbon reserves will be discovered and economically produced. Operational risks include competition, reservoir performance uncertainties, environmental factors, and regulatory, environment and safety concerns. Financial risks associated with the petroleum industry include fluctuations in commodity prices, interest rates, currency exchange rates and the cost of goods and services.

### *Global Financial Crisis*

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and existed throughout 2009, and are continuing in 2010. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies.

### *Capital Requirements*

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As the Corporation's revenues have declined as a result of decreased commodity pricing, it has been required to reduce capital expenditures. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Corporation to additional access to capital risk. While the Corporation did complete two equity financings in 2009, there can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

### *Financial Risks*

Financial risks include fluctuations in commodity prices, interest rates and the Canadian/US dollar exchange rate, and the cost of goods and services. The Corporation currently has financial contracts with Canadian banks (see "Commodity Pricing and Marketing" for details). The Corporation also manages these risks by maintaining a balance sheet with prudent levels of debt measured by debt to funds from operations and debt coverage ratios. This allows for sufficient financial capacity to maintain exploration and development activities in any downturn in commodity prices.

### *Third Party Credit Risk*

An additional risk is credit risk for failure of performance by counter-parties. This risk is controlled by an evaluation of the credit risk before contract initiation and ensuring product sales and delivery contracts are made with well-known and financially strong crude oil and natural gas marketers.

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

### *Environmental*

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. 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 liability and potentially increased capital expenditures and operating costs. Implementation of strategies for reducing greenhouse gases to meet the limits required could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict either the nature of those requirements or the impact on the Corporation and its operations and financial condition.

## Critical Accounting Estimates

There are a number of critical estimates underlying the accounting policies employed in preparing the Financial Statements.

### *Oil and Gas Accounting*

Galleon follows the full cost method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development are capitalized whether successful or not. The aggregate of net capitalized costs and estimated future development costs less estimated salvage values is amortized using the unit-of-production method based on estimated proved oil and gas reserves.

### *Proved Reserves*

Full cost accounting relies on the estimated proved reserves believed to be recoverable from the oil and gas properties. Determination of reserves is a complex process involving judgments, estimates and decisions based on available geological, engineering/production and other relevant economic data. These estimates are subject to change as economic conditions change and ongoing production and development activities provide new information. The Corporation's reserves are evaluated annually by an independent firm and by the Corporation on a quarterly basis. Reserve estimates are critical to the following accounting estimates:

- Calculation of unit of production depletion. Proved reserve estimates are used to determine the depletion and depreciation rate applied to each unit of production.
- Ceiling test calculation, measurement and impairment of oil and gas assets. Estimated future undiscounted cash flows are determined using the estimate of proved reserves.

An increase in estimated proved oil and gas reserves would result in a corresponding reduction in depletion expense. A decrease in estimated future development costs would result in a corresponding reduction in depletion expense.

The calculation of proved reserves is affected by events, including the following:

- Changes to commodity prices
- Production performance of wells
- Changes to reservoir performance/pressures
- New geological and geophysical data
- Competitor production practices
- Changes to government regulations

As circumstances change and additional data becomes available, revisions are made to these estimates.

### *Unproved Properties*

Certain costs related to unproved properties may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted. The costs related to unproved properties are also excluded from the book value subject to the ceiling test measurement and are assessed for impairment separately.

### *Full Cost Accounting Ceiling Test*

The Corporation is required to review the carrying value of all property, plant and equipment, including the carrying value of oil and gas assets, for potential impairment. Impairment is indicated if the carrying

value of the long-lived asset or oil and gas cost centre is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings.

The ceiling test is based on estimates of reserves, production rate, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

#### *Asset Retirement Obligation*

The Corporation is required to provide for future abandonment and site restoration costs. The Corporation must estimate these costs in accordance with existing laws, contracts or other policies. These estimated costs are charged to property, plant and equipment and the appropriate liability account over the expected service life of the asset. The estimate of future removal and site restoration costs involves a number of estimates related to timing of abandonment, determination of economic life of the asset, costs associated with abandonment and site restoration, and review of potential abandonment methods.

#### *Income Tax Accounting*

The determination of the Corporation's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment subsequent to the financial statement reporting period. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

#### *Goodwill*

The Company recognizes goodwill on corporate acquisitions when the total purchase price exceeds the fair value of net identifiable assets and liabilities of the acquired entity. Goodwill is tested quarterly for impairment or as events occur that could result in impairment. Impairment is recognized based on the fair value of the Corporation compared to the book value of the Corporation. If the fair value of the Corporation is less than the book value, impairment is measured allocating the fair value to the identifiable assets and liabilities as if the Corporation had been acquired in a business combination for its fair value. The excess of the fair value over the amounts assigned to the identifiable assets and liabilities is the fair value of the goodwill. Any excess of the book value over this implied fair value of goodwill is the impairment amount. Impairment is charged to earnings in the period which it occurs. Goodwill is stated at cost less impairment and is not amortized.

### **Changes in Accounting Policies**

The Canadian Accounting Standards Board (AcSB) has confirmed that the use of the International Financial Reporting Standards ("IFRS") will be required in 2011 for publicly accountable profit-oriented enterprises. IFRS will replace Canada's GAAP for those enterprises that are responsible to large or diverse groups of stakeholders. The official changeover date is for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. Corporations will be required to provide comparative IFRS information for the fiscal year of 2010.

The Corporation's conversion project consists of the following phases: 1) initial diagnostic and planning, 2) impact analysis and evaluation, and 3) implementation and review. The Corporation has completed the initial diagnostic and planning phase which included identifying major differences between Canadian GAAP and IFRS. The impact analysis and evaluation phase is nearing completion.

It is expected that share based payments, income taxes, asset retirement obligations and accounting for property and equipment, including accounting for and assessing depletion and impairment, will be impacted by the conversion to IFRS. The Corporation has not yet finalized its accounting policies and as such is unable to quantify the impact of adopting IFRS on the financial statements.

The impact of the transition to IFRS on the internal controls over financial reporting will be updated as the review of the Corporation's accounting policies is completed.

In July 2009, the International Accounting Standards Board (IASB) issued an amendment to IFRS 1 "First Time Adoption of International Reporting Standards". The amendment allows full cost accounting corporations to elect, at the time of adoption, to measure exploration and evaluation assets at the amount determined under the entity's previous GAAP. The amendment will also permit full cost accounting corporations to measure, at the time of adoption, oil and gas assets in the development or production phases, by using the total value determined under the entity's previous GAAP and allocating values at the unit of account level based on the Corporation's reserve volumes or reserve values as of the date of conversion. This exemption will relieve the Corporation from retrospective application of IFRS for its oil and gas assets. The Corporation expects this exemption will be used, and that values at the unit of account level will be allocated based on reserve values at the date of conversion.

Assets are required to be assessed for impairment upon transition to IFRS. Under IFRS, the impairment test compares the carrying value of an asset to the greater of its fair value or value in use. IFRS impairment calculations are done at an asset or cash-generating unit (CGU) level, compared to being calculated at the country cost centre under Canadian GAAP. CGUs are identified on the basis of cash inflows being independent from other assets or groups of assets. The Corporation is currently finalizing the CGU determination and impairment calculations.

Under current Canadian GAAP, the Corporation's petroleum and natural gas properties are depleted on the unit-of-production method using estimated proven petroleum and natural gas reserves. Under IFRS, the Corporation has the option to deplete these assets on a unit of production basis, using a reserve base of proved or proved plus probable reserves. The Corporation expects to deplete petroleum and natural gas properties using proved plus probable reserves.

The asset retirement obligation under IFRS may be calculated using a risk free or credit adjusted risk free discount rate. The Corporation expects to continue its current Canadian GAAP policy of calculating the asset retirement obligation using a credit adjusted risk free rate.

Audit work on the opening balance sheet has commenced and is expected to be completed during the fourth quarter of 2010. As required, the Corporation will be preparing IFRS based comparative statements for each of the quarters ended in 2010 following completion of the opening 2010 balance sheet.

## **Controls and Procedures over Financial Reporting**

### **Disclosure Controls and Procedures**

The Corporation's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the Corporation's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

### **Internal Controls over Financial Reporting**

The CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Corporation's

financial reporting and the preparation of financial statements for external purposes in accordance with the Canadian GAAP.

The Corporation's CEO and CFO are required to cause the Corporation to disclose any change in the Corporation's internal controls over financial reporting that occurred during the Corporation's most recent interim period that has materially affected, or is reasonably likely to materially affect, the Corporation's internal controls over financial reporting. No material changes in the Corporation's internal controls over financial reporting were identified during such period that has materially affected, or are reasonably likely to materially affect, the Corporation's internal controls over financial reporting.

It should be noted that a control system, including the Corporation's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

## Share Information

The following table summarizes the outstanding shares of Galleon as of September 30:

	2010	2009
Class A shares outstanding		
Basic	84,758,083	82,890,883
Diluted <sup>1</sup>	84,838,083	82,890,883

<sup>1</sup> Includes 80,000 options at September 30, 2010 (September 30, 2009 – nil)

At September 30, 2010, the market value of Galleon's Class A shares was \$298.3 million based on the closing price of \$3.52 per share. As of November 11, 2010, the number of Class A shares and options outstanding were 83,980,083 and 5,660,500 respectively.

## Additional Information

Additional information relating to Galleon, including Galleon's Annual Information Form, can be accessed on-line on SEDAR at [www.sedar.com](http://www.sedar.com), or from the Corporation's website at [www.galleonenergy.com](http://www.galleonenergy.com).

## Outlook

Quarterly Highlights	2010				2009			2008
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
<b>Production</b>								
Light oil (Bbl/d)	2,517	3,295	3,249	3,364	3,872	4,024	4,447	5,199
Heavy oil (Bbl/d)	1,009	1,108	1,161	1,210	1,281	1,198	1,227	1,338
Natural Gas (Mcf/d)	59,186	67,689	64,165	57,752	57,012	61,733	69,632	67,875
Liquids (Bbl/d)	433	537	527	489	561	565	687	604
<b>BOE/d</b>	<b>13,823</b>	<b>16,222</b>	<b>15,631</b>	<b>14,688</b>	<b>15,216</b>	<b>16,076</b>	<b>17,965</b>	<b>18,453</b>
Total BOE produced	1,271,739	1,476,256	1,406,752	1,351,338	1,399,847	1,462,922	1,616,979	1,697,711
<b>Daily BOE of production per million Class A shares – basic</b>	<b>163</b>	<b>191</b>	<b>184</b>	<b>174</b>	<b>184</b>	<b>211</b>	<b>239</b>	<b>250</b>
<b>Prices</b> (prior to realized gains or losses on financial contracts and prior to transportation)								
Light oil (\$/Bbl)	71.26	72.53	77.47	72.88	67.12	61.39	47.53	61.69
Heavy oil (\$/Bbl)	58.13	57.76	64.91	62.23	57.27	51.54	33.65	39.36
Crude oil (\$/Bbl)	67.50	68.82	74.17	70.06	64.67	59.13	44.53	57.12
Natural Gas (\$/Mcf)	3.75	4.07	5.22	4.60	3.16	3.61	5.13	6.97
NGLs (\$/Bbl)	49.48	53.41	56.80	52.06	43.87	39.23	34.07	42.76
<b>Per BOE (\$)</b>								
Revenues	34.82	37.44	44.28	41.65	35.36	34.43	35.24	47.29
Royalties, net of GCA	(4.16)	(6.71)	(7.59)	(6.91)	(7.10)	(2.11)	(6.40)	(6.51)
Transportation costs	(1.66)	(1.64)	(1.56)	(1.33)	(1.41)	(1.41)	(1.45)	(1.39)
Operating costs	(10.20)	(9.03)	(8.88)	(9.31)	(9.32)	(9.43)	(10.70)	(12.20)
<b>Net</b>	<b>18.80</b>	<b>20.06</b>	<b>26.25</b>	<b>24.10</b>	<b>17.53</b>	<b>21.48</b>	<b>16.69</b>	<b>27.19</b>
Other revenue	-	-	-	-	-	0.05	0.42	0.06
G&A	(3.09)	(2.07)	(2.54)	(3.28)	(2.47)	(2.62)	(2.60)	(2.37)
Restructuring costs	(0.05)	(0.81)	-	-	-	-	-	-
Interest	(1.45)	(2.42)	(2.14)	(2.27)	(2.05)	(1.16)	(0.98)	(1.53)
Capital and other taxes	(0.05)	0.02	(0.07)	(0.07)	(0.07)	(0.11)	(0.04)	(0.05)
Realized gain (loss) on financial derivative	1.90	3.61	1.02	(1.60)	0.50	2.58	2.68	15.78
<b>Funds from operations<sup>1</sup></b>	<b>16.06</b>	<b>18.39</b>	<b>22.52</b>	<b>16.88</b>	<b>13.44</b>	<b>20.22</b>	<b>16.17</b>	<b>39.08</b>

<sup>1</sup>See "Non-GAAP Measurements"

Quarterly Highlights (unaudited)	2010			2009
	Q3	Q2	Q1	Q4
<b>Financial</b> (\$000s)				
Revenues	44,279	55,273	62,284	56,287
Operating costs	(12,978)	(13,328)	(12,487)	(12,582)
General & administrative expenses	(3,930)	(3,063)	(3,568)	(4,430)
Restructuring costs	(59)	(1,183)	-	-
Interest expense	(1,849)	(3,578)	(3,014)	(3,063)
<b>Funds from operations<sup>1</sup></b>	<b>20,425</b>	<b>27,146</b>	<b>31,680</b>	<b>22,820</b>
Per share, basic <sup>1</sup>	0.24	0.32	0.37	0.27
Per share, diluted <sup>1</sup>	0.24	0.32	0.37	0.27
<b>Earnings (loss)</b>	<b>(5,621)</b>	<b>2,328</b>	<b>12,491</b>	<b>(5,654)</b>
Per share, basic	(0.07)	0.03	0.15	(0.07)
Per share, diluted	(0.07)	0.03	0.15	(0.07)
<b>Total assets</b>	<b>1,026,875</b>	<b>1,010,855</b>	<b>1,175,832</b>	<b>1,136,732</b>
Weighted average outstanding Class A shares-basic	84,869,236	85,143,751	85,098,939	84,325,666
Weighted average outstanding Class A shares-diluted	84,869,236	85,143,751	85,098,939	84,325,666

Quarterly Highlights (unaudited)	2009			2008
	Q3	Q2	Q1	Q4
<b>Financial</b> (\$000s)				
Revenues	49,497	50,373	56,987	80,280
Operating costs	(13,045)	(13,790)	(17,297)	(20,704)
General & administrative expenses	(3,453)	(3,827)	(4,201)	(4,019)
Restructuring costs	-	-	-	-
Interest expense	(2,876)	(1,702)	(1,585)	(2,599)
<b>Funds from operations<sup>1</sup></b>	<b>18,818</b>	<b>29,605</b>	<b>26,150</b>	<b>66,365</b>
Per share, basic <sup>1</sup>	0.23	0.39	0.35	0.90
Per share, diluted <sup>1</sup>	0.23	0.39	0.35	0.90
<b>Earnings (loss)</b>	<b>(1,815)</b>	<b>(22,012)</b>	<b>(5,091)</b>	<b>25,113</b>
Per share, basic	(0.02)	(0.29)	(0.07)	0.34
Per share, diluted	(0.02)	(0.29)	(0.07)	0.34
<b>Total assets</b>	<b>1,127,665</b>	<b>1,141,506</b>	<b>1,158,329</b>	<b>1,181,003</b>
Weighted average outstanding Class A shares-basic	82,890,883	76,040,581	75,231,828	73,710,516
Weighted average outstanding Class A shares-diluted	82,890,883	76,040,581	75,231,828	74,032,935

<sup>1</sup> See "Non-GAAP Measurements"

**GALLEON ENERGY INC.**

**Financial Statements  
(unaudited)**

**September 30, 2010**

**GALLEON ENERGY INC.**  
**Consolidated Balance Sheets**

(\$000s) (unaudited)	September 30, 2010	December 31, 2009
<b>ASSETS</b>		
CURRENT		
Accounts receivable	28,144	41,270
Deposits and prepaid expenses	4,455	6,190
Future income taxes (note 7)	-	2,884
Fair value of financial derivatives (note 9)	19,046	4,241
	<u>51,645</u>	<u>54,585</u>
Goodwill (note 3)	30,155	34,891
Fair value of financial derivatives (note 9)	3,704	-
Equipment inventory	6,526	6,116
Property and equipment (notes 3, 4, and 5)	934,845	1,041,140
	<u><b>1,026,875</b></u>	<u><b>1,136,732</b></u>
<b>LIABILITIES</b>		
CURRENT		
Accounts payable and accrued liabilities	50,048	55,531
Capital lease (note 3)	-	1,545
Future income taxes (note 7)	4,067	-
Bank loan (note 5)	122,283	217,243
Fair value of financial derivatives (note 9)	3,099	13,789
	<u>179,497</u>	<u>288,108</u>
Asset retirement obligation (note 4)	41,986	41,499
Fair value of financial derivatives (note 9)	11,194	-
Future income taxes (note 7)	77,002	94,262
	<u>309,679</u>	<u>423,869</u>
<b>SHAREHOLDERS' EQUITY</b>		
Share capital (note 6)	588,174	599,334
Contributed surplus (note 6)	35,179	28,884
Retained earnings	93,843	84,645
	<u>717,196</u>	<u>712,863</u>
	<u><b>1,026,875</b></u>	<u><b>1,136,732</b></u>

*See accompanying notes*

**GALLEON ENERGY INC.****Consolidated Statements of Earnings (Loss), Comprehensive Income (Loss) and Retained Earnings**

(\$000s, except per share amounts) (unaudited)	Three months ended		Nine months ended	
	September 30		September 30	
	2010	2009	2010	2009
<b>REVENUE</b>				
Petroleum and natural gas revenue	44,279	49,497	161,836	156,857
Royalties, net of GCA	(5,280)	(9,940)	(25,877)	(23,375)
Realized gain on financial derivatives (note 9)	2,420	699	9,184	8,810
Unrealized gain (loss) on financial derivative (note 9)	428	13,342	18,005	(6,966)
Other income	-	6	-	752
	41,847	53,604	163,148	136,078
<b>EXPENSES</b>				
Operating	12,978	13,045	38,793	44,132
Transportation	2,110	1,970	6,721	6,368
General and administration	3,930	3,453	10,561	11,481
Restructuring costs (note 11)	59	-	1,242	-
Goodwill allocated to disposed properties (note 3)	-	-	4,736	-
Interest	1,849	2,876	8,441	6,163
Stock-based compensation (note 6)	171	2,487	2,873	5,056
Accretion	712	664	2,149	1,987
Depletion and depreciation	29,547	30,600	93,071	98,389
	51,356	55,095	168,587	173,576
<b>Loss before taxes</b>	(9,509)	(1,491)	(5,439)	(37,498)
<b>Income taxes</b> (note 7)				
Capital and other taxes	68	100	134	327
Future income taxes (recovery)	(3,956)	224	(14,771)	(8,907)
	(3,888)	324	(14,637)	(8,580)
<b>NET EARNINGS (LOSS) AND COMPREHENSIVE INCOME (LOSS)</b>	<b>(5,621)</b>	<b>(1,815)</b>	<b>9,198</b>	<b>(28,918)</b>
<b>RETAINED EARNINGS, BEGINNING OF PERIOD</b>	99,464	92,114	84,645	119,217
<b>RETAINED EARNINGS, END OF PERIOD</b>	93,843	90,299	93,843	90,299
<b>NET EARNINGS (LOSS) AND COMPREHENSIVE INCOME (LOSS) PER SHARE</b> (note 6)				
<b>Basic</b>	(0.07)	(0.02)	0.11	(0.37)
<b>Diluted</b>	(0.07)	(0.02)	0.11	(0.37)
<i>Weighted average Class A shares – basic</i>	84,869,236	82,890,883	85,036,467	78,082,486
<i>– diluted</i>	84,869,236	82,890,883	85,048,031	78,082,486

See accompanying notes

**GALLEON ENERGY INC.**  
**Consolidated Statements of Cash Flows**

(\$000s) (unaudited)

	Three months ended September 30		Nine months ended September 30	
	2010	2009	2010	2009
<b>Cash provided by (used in):</b>				
<b>OPERATING ACTIVITIES</b>				
Net (loss) earnings	(5,621)	(1,815)	9,198	(28,918)
Items not requiring cash:				
Future income taxes (recovery)	(3,956)	224	(14,771)	(8,907)
Depletion and depreciation	29,547	30,600	93,071	98,389
Accretion	712	664	2,149	1,987
Stock-based compensation	171	2,487	2,873	5,056
Unrealized loss (gain) on financial derivative	(428)	(13,342)	(18,005)	6,966
Goodwill allocated to disposed properties	-	-	4,736	-
Abandonment costs	(130)	(524)	(391)	(1,048)
Change in non-cash working capital	5,403	1,413	3,773	9,029
	25,698	19,707	82,633	82,554
<b>FINANCING ACTIVITIES</b>				
Issue of common shares	-	-	268	36,695
Repurchase of common shares	(3,544)	-	(3,544)	(32)
Share issue costs	-	(25)	-	(1,741)
Capital lease payment	(1,135)	(1,313)	(1,545)	(1,719)
Bank loan (repayment)	10,564	(5,030)	(94,960)	(18,216)
	5,885	(6,368)	(99,781)	14,987
<b>INVESTING ACTIVITIES</b>				
Disposal of (additions to) equipment inventory	(309)	2,179	(410)	6,599
Additions to oil and gas properties	(40,746)	(29,873)	(102,409)	(79,815)
Acquisition of oil and gas properties (note 3)	(684)	(162)	(17,650)	(230)
Disposition of oil and gas properties (note 3)	1,100	756	132,012	5,389
Change in non-cash working capital	9,056	13,761	5,605	(29,484)
	(31,583)	(13,339)	17,148	(97,541)
<b>CHANGE IN CASH</b>	-	-	-	-
<b>CASH, BEGINNING AND END OF PERIOD</b>	-	-	-	-
<b>SUPPLEMENTARY INFORMATION</b>				
Cash interest paid	1,309	2,423	8,049	6,668
Cash taxes paid	93	252	279	627

*See accompanying notes*

**Notes to the Financial Statements**  
**For the three and nine month periods ended September 30, 2010 and 2009**  
**(unaudited)**

Unless otherwise stated, amounts presented in these notes are in Canadian dollars and tabular amounts are in thousands of Canadian dollars, except number of shares and per share amounts.

**1. ACCOUNTING POLICIES**

*Nature of Business and Basis of Presentation*

Galleon Energy Inc. (“Galleon” or the “Corporation”) was incorporated under the Business Corporations Act of Alberta on March 27, 2003. The business of the Corporation is the acquisition of, exploration for and development of petroleum and natural gas properties in western Canada. Galleon is listed on the TSX under the symbol “GO”.

These unaudited interim consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (“GAAP”), and follow the same accounting policies as the financial statements for the year ended December 31, 2009, except as noted below.

These notes do not include all disclosures required in annual financial statements and are incremental to, and should be read in conjunction with, the audited financial statements for the year ended December 31, 2009.

**2. CHANGES IN SIGNIFICANT ACCOUNTING POLICIES**

*Future accounting policies*

The Canadian Accounting Standards Board (AcSB) has confirmed that the use of the International Financial Reporting Standards (“IFRS”) will be required in 2011 for publicly accountable profit-oriented enterprises. IFRS will replace Canada’s GAAP for those enterprises that are responsible to large or diverse groups of stakeholders. The official changeover date is for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. Corporations will be required to provide comparative IFRS information for the fiscal year of 2010.

The Corporation’s conversion project consists of the following phases: 1) initial diagnostic and planning, 2) impact analysis and evaluation, and 3) implementation and review. The Corporation has completed the initial diagnostic and planning phase which included identifying major differences between Canadian GAAP and IFRS. The impact analysis and evaluation phase is nearing completion.

It is expected that share based payments, income taxes, asset retirement obligations and accounting for property and equipment, including accounting for and assessing depletion and impairment, will be impacted by the conversion to IFRS. The Corporation has not yet finalized its accounting policies and as such is unable to quantify the impact of adopting IFRS on the financial statements.

The impact of the transition to IFRS on the internal controls over financial reporting will be updated as the review of the Corporation’s IFRS accounting policies is completed.

In July 2009, the International Accounting Standards Board (IASB) issued an amendment to IFRS 1 “First Time Adoption of International Reporting Standards”. The amendment allows full cost accounting corporations to elect, at the time of adoption, to measure exploration and evaluation assets at the amount determined under the entity’s previous GAAP. The amendment will also permit full cost accounting corporations to measure, at the time of adoption, oil and gas assets in the development or production phases, by using the total value determined under the entity’s previous GAAP and allocating values at the unit of account level based on the Corporation’s reserve volumes or reserve values as of the date of conversion. This exemption will relieve the Corporation from retrospective application of IFRS for its oil and gas assets. The Corporation expects this exemption will be used, and that values at the unit of account level will be allocated based on reserve values at the date of conversion.

Assets are required to be assessed for impairment upon transition to IFRS. Under IFRS, the impairment test compares the carrying value of an asset to the greater of its fair value less costs to sell or value in use. IFRS impairment calculations are done at an asset or cash-generating unit (CGU) level, compared to being calculated at the country cost centre under Canadian GAAP. CGUs are identified on the basis of cash inflows being independent from other assets or groups of assets. The Corporation is currently finalizing the CGU determination and impairment calculations.

Under current Canadian GAAP, the Corporation's petroleum and natural gas properties are depleted on the unit-of-production method using estimated proven petroleum and natural gas reserves. Under IFRS, the Corporation has the option to deplete these assets on a unit of production basis, using a reserve base of proved or proved plus probable reserves. The Corporation expects to deplete petroleum and natural gas properties using proved plus probable reserves.

The asset retirement obligation under IFRS may be calculated using a risk free or credit adjusted risk free discount rate. The Corporation expects to continue its current Canadian GAAP policy of calculating the asset retirement obligation using a credit adjusted risk free rate.

Audit work on the opening balance sheet has commenced and is expected to be completed during the fourth quarter of 2010. As required, the Corporation will be preparing IFRS based comparative statements for each of the quarters ended in 2010 following completion of the opening 2010 balance sheet.

### 3. PROPERTY AND EQUIPMENT

	Cost	Accumulated depletion	Net book value
As at September 30, 2010	\$	\$	\$
Petroleum and natural gas properties & equipment	1,504,455	(570,840)	933,615
Office furniture and equipment	2,631	(1,401)	1,230
	<b>1,507,086</b>	<b>(572,241)</b>	<b>934,845</b>

  

	Cost	Accumulated depletion	Net book value
As at December 31, 2009	\$	\$	\$
Petroleum and natural gas properties & equipment	1,517,757	(477,996)	1,039,761
Office furniture and equipment	2,553	(1,174)	1,379
	<b>1,520,310</b>	<b>(479,170)</b>	<b>1,041,140</b>

During the nine months ended September 30, 2010 the Corporation sold properties in the Puskwa area of Alberta for cash consideration, net of adjustments, of \$131.5 million. Proceeds from the sale were applied against property and equipment, with no gain or loss recognized, as the sale did not change the depletion rate by 20% or more. Goodwill was reduced by \$4.7 million as a result of the sale.

During nine months ended September 30, 2010 the Corporation purchased non-producing assets in the Kakut area of Alberta for cash consideration of \$17.5 million.

As at September 30, 2010, \$58.4 million (September 30, 2009- \$100.1 million) of undeveloped land and seismic have been excluded from and \$147.0 million (September 30, 2009 - \$177.2 million) in future development costs have been added into the full cost pool for depletion purposes. For the three and nine months ended September 30, 2010, \$445,000 and \$990,000, respectively (September 30, 2009 – \$273,000 and \$818,000) of exploration salaries have been capitalized.

The final payment required under the equipment lease financing arrangement was made during the three months ended September 30, 2010.

During the nine months ended September 30, 2009, certain minor properties were sold for net proceeds of \$5.4 million.

#### 4. ASSET RETIREMENT OBLIGATION

The Corporation's asset retirement obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Corporation estimates the total undiscounted amount of cash flows required to settle its asset retirement obligation is approximately \$126 million, which will be incurred over the next 40 years. Credit adjusted risk free rates of 5% and 8% and an inflation rate of 2% were used to calculate the fair value of the asset retirement obligation.

	Nine months ended September 30, 2010 \$	Year ended December 31, 2009 \$
Balance, beginning of year	41,499	39,905
Accretion expense	2,149	2,651
Liabilities incurred	1,488	1,909
Disposition of liabilities	(1,839)	(1,685)
Settlement of liabilities	(391)	(1,281)
Change in estimates	(920)	-
<b>Balance, end of period</b>	<b>41,986</b>	<b>41,499</b>

#### 5. AVAILABLE CREDIT FACILITY

The Corporation has \$250 million in credit facilities available consisting of a \$225 million extendible 364 day revolving term facility and a \$25 million non-revolving facility. The \$25 million facility is available subject to mutual approval of the banking syndicate and the Corporation, including repayment terms. Collateral for the facilities consists of a demand debenture for \$500 million collateralized by a first floating charge over all of the property and equipment of the Corporation. At September 30, 2010, an amount of \$122.3 million was drawn against the credit facilities (December 31, 2009 - \$217.2 million).

The facilities bear interest at the bank's prime or banker's acceptance rates plus a rate margin. The margin ranges from 1.5% per annum to 5.5% per annum, based upon the Corporation's debt to cash flow ratio. For the three and nine months ended September 30, 2010, the effective interest rates were 6.6% and 6.0%, respectively (September 30, 2009 - 4.8% and 3.3%).

#### 6. SHARE CAPITAL

##### *Authorized*

Unlimited number of preferred shares with no par value

Unlimited number of voting Class A shares with no par value

Unlimited number of voting Class B shares with no par value

Class A Shares	Number of Shares	Amount \$
<b>Balance at December 31, 2008</b>	<b>75,170,733</b>	<b>547,298</b>
Issued for cash on exercise of stock options	230,250	695
Common shares purchased (d)	(10,100)	(32)
Issued for cash (c)	7,500,000	36,000
Issued for cash (b)	2,200,000	17,160
Share issue costs, net of tax of \$712	-	(2,025)
Transfer from contributed surplus	-	238
<b>Balance at December 31, 2009</b>	<b>85,090,883</b>	<b>599,334</b>
Tax effect of flow through shares (a)	-	(4,462)
Issued for cash on exercise of stock options	45,000	212
Transfer from contributed surplus	-	78
<b>Balance at March 31, 2010</b>	<b>85,135,883</b>	<b>595,162</b>
Issued for cash on exercise of stock options	12,000	56
Transfer from contributed surplus	-	21
<b>Balance at June 30, 2010</b>	<b>85,147,883</b>	<b>595,239</b>
Common shares purchased (d)	-	(3,544)
Transfer from contributed surplus on purchase of shares (d)	-	(3,521)
Cancellation of shares purchased (d)	(389,800)	-
<b>Balance at September 30, 2010</b>	<b>84,758,083</b>	<b>588,174</b>

- a) The tax effect of \$4.5 million related to the renouncement in February 2010 of flow-through shares issued in 2009 was recorded in 2010.
- b) On November 2, 2009, the Corporation issued 2,200,000 flow-through Class A shares at \$7.80 per share by way of a private placement for gross proceeds of \$17,160,000. The Corporation is obligated to incur qualifying exploration expenses of \$17,160,000 prior to December 31, 2010. As at September 30, 2010, \$15.5 million of the required qualifying expenditures have been incurred.
- c) On June 23, 2009, the Corporation issued 7,500,000 Class A shares at \$4.80 per share for cash proceeds of \$36.0 million.
- d) On November 24, 2008, the Corporation received regulatory approval for a Normal Course Issuer Bid (“Bid”) to purchase, for cancellation, up to a maximum of 5,610,908 shares of the Corporation. The Bid commenced on November 26, 2008 and terminated on November 25, 2009. In 2009 the Corporation purchased 10,100 shares for total consideration of \$32,627.

On November 26, 2009, the Corporation received regulatory approval for a renewal of the Bid, with approval to purchase, for cancellation, up to a maximum of 1,000,000 Class A shares of the Corporation. The renewal commenced on December 1, 2009 and will terminate on November 30, 2010. Regulatory approval for an amendment to the Bid, increasing the maximum number of shares that may be purchased to 2,000,000, was received on September 17, 2010.

During the nine months ended September 30, 2010, the Corporation purchased 1,010,600 shares for cancellation for \$3,544,000, of which 389,800 shares were cancelled at September 30, 2010. Share capital has been reduced and contributed surplus has been increased by \$3,521,000, being the difference between the assigned value of the shares at the date of purchase and the purchase price of the shares.

The Corporation has a share option plan which was approved on May 19, 2005 and amended on August 25, 2005, June 19, 2007 and May 13, 2008. The exercise price of each option may not be less than the closing price of the Corporation’s Class A shares on the trading day immediately prior to the date of the grant. Compensation expense is recognized as the options vest. With options granted

prior to November 2008, one third of the options vest immediately, and one third vest on each of the first and second anniversaries of the date of the grant. With options granted commencing November 2008, the vesting period is one third on each of the next three anniversaries of the date of the grant. The options expire five years from the date of grant. The Corporation may grant up to 10% of the aggregate number of Class A shares outstanding and no one optionee is permitted to hold options entitling such optionee to purchase more than 5% of the aggregate number of issued and outstanding Class A shares. Class A shares have been reserved for all options granted.

	Nine months ended September 30, 2010	Year ended December 31, 2009
Contributed Surplus	\$	\$
Beginning of period	28,884	23,009
Stock based compensation expense	2,873	6,114
Transfer to share capital on purchase of shares	3,521	-
Transfer to share capital	(99)	(238)
Paid on surrender of share options	-	(1)
<b>End of period</b>	<b>35,179</b>	<b>28,884</b>

The fair value of options granted was estimated at the date of grant using a Black-Scholes Option Pricing Model with the following assumptions: risk-free interest rates of 1.33-4.51%; dividend yield of 0%; volatility factors of the market price of the Corporation's common shares of 36-63%; and an average expected life of the options of 3 years.

Options	Number of Shares	Weighted Average Exercise Price \$
<b>Outstanding, December 31, 2008</b>	<b>7,037,651</b>	<b>11.87</b>
Granted	5,526,000	6.26
Forfeited	(514,500)	(10.98)
Surrendered for cancellation	(5,085,067)	(13.92)
Exercised	(230,250)	(3.02)
<b>Outstanding, December 31, 2009</b>	<b>6,733,834</b>	<b>6.08</b>
Granted	699,000	5.52
Forfeited	(172,000)	(5.91)
Exercised	(45,000)	(4.70)
<b>Outstanding, March 31, 2010</b>	<b>7,215,834</b>	<b>6.04</b>
Granted	-	-
Forfeited	(204,000)	(5.77)
Exercised	(12,000)	(4.70)
<b>Outstanding, June 30, 2010</b>	<b>6,999,834</b>	<b>6.04</b>
Granted	300,000	3.56
Forfeited	(1,516,333)	5.92
<b>Outstanding, September 30, 2010</b>	<b>5,783,501</b>	<b>5.95</b>

#### *Earnings per share*

The Corporation utilizes the treasury stock method in the determination of diluted per share amounts. Under this method, the diluted weighted average number of shares is calculated assuming the proceeds that arise from the exercise of outstanding and in the money options are used to purchase common shares of the Corporation at their average market price for the period.

## 7. INCOME TAXES

The future income tax liability is comprised of the following temporary differences as at:

	September 30, 2010	December 31, 2009
	\$	\$
Property and equipment	74,638	99,668
ACRI benefit	(1,302)	(1,260)
Share issue costs	(953)	(1,770)
Asset retirement obligation	(1,619)	(1,193)
Non-capital losses	(14,395)	(28,932)
Partnership income tax deferral	22,543	27,749
Capital leases	-	(402)
Financial derivative	2,157	(2,482)
Future income tax liability	81,069	91,378
Current future income tax asset (liability)	(4,067)	2,884
<b>Long term future income tax liability</b>	<b>77,002</b>	<b>94,262</b>

The income tax recovery recorded during the nine months ended September 30, 2010 includes a \$12.1 million benefit relating to the disposition of properties, and a \$1.9 million benefit arising from a reduction in the expected future tax rate.

## 8. COMMITMENTS

### *Office lease payments*

At September 30, 2010 the Corporation is committed to future minimum payments under operating leases for office space as follows:

	Amount \$
2010	448
2011	1,793
2012	1,793
2013	1,793
2014	1,793
2015	1,793
Thereafter	2,689

### *Litigation*

The Corporation is involved in various claims and legal actions arising from the normal course of business. The Corporation does not expect that the outcome of these proceedings will have a material adverse effect on the Corporation as a whole.

## 9. FINANCIAL INSTRUMENTS AND FINANCIAL RISK FACTORS

### *Fair value of financial assets*

The Corporation's financial instruments recognized in the balance sheet consist of accounts receivable, accounts payable, bank loan and financial derivatives ("financial instruments"). The carrying value of accounts receivable and accounts payable approximated their fair values at September 30, 2010 due to their short-term nature. The carrying value of the bank loan approximates fair value due to the floating interest rate on the facility. The fair value of the financial derivatives is recognized on the balance sheet as described below.

### *Credit risk*

Credit risk is the risk that a customer or counterparty will fail to perform an obligation or fail to pay amounts due causing a financial loss. The Corporation's accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal credit risks. A small portion of the Corporation's production is currently sold through joint venture partners under normal industry sale and payment terms. As at September 30, 2010, approximately 45% of the accounts receivable balance is due from three customers, compared to 41% due from three customers at December 31, 2009. These customers are considered to have high credit worthiness. The Corporation generally grants unsecured credit but routinely assesses the financial strength of its customers and joint venture partners. No provision has been made for past due receivables as of September 30, 2010 as the Corporation has assessed there are no impaired receivables.

<b>Accounts Receivable</b>	<b>\$</b>
Less than 90 days	21,852
Greater than 90 days	6,292
Total	28,144

### *Liquidity risk*

Liquidity risk arises through excess financial obligations over available financial assets due at any point in time. The Corporation's objective in managing liquidity risk is to maintain sufficient available reserves in order to meet its liquidity requirements at any point in time. The Corporation believes that it has access to sufficient capital through internally generated cash flows and external equity sources, and to undrawn committed credit facilities to meet current spending forecasts. All of the Corporation's current liabilities mature within a one year period.

### *Interest rate risk*

The Corporation is exposed to interest rate risk as changes in interest rates may affect future cash flows and the fair value of its financial instruments. The Corporation's primary debt facility has a floating interest rate that will fluctuate based on prevailing market conditions. Cash flows are sensitive to changes in interest rates on this instrument. Given the amount of debt employed, the Corporation's strategy is to manage interest rate risk. If interest rates on the floating instrument were to change by 1% it is estimated that annual cash flow would change by approximately \$1.1 million.

### *Market risk*

Market risk is the risk of uncertainty arising from possible market price movements and their impact on the future performance of the business. The market price movements that could adversely affect the value of the Corporation's financial assets, liabilities and expected future cash flows include commodity price risk and interest rate risk. It is estimated that annual budgeted cash flow, excluding the Puskwa assets sold, would change approximately by \$1.2 million and by \$3.9 million, respectively, due to a \$1 USD WTI and a \$0.25/Mcf CDN change in oil and natural gas prices.

The Corporation has the following financial contracts in place as at September 30, 2010:

Natural Gas:

January 1, 2010 - December 31, 2011	5,000 GJ/d	CDN \$5.85/GJ
January 1, 2010 - December 31, 2011	5,000 GJ/d	CDN \$5.75/GJ
April 1, 2010 - March 31, 2011	5,000 GJ/d	CDN \$5.76/GJ
January 1, 2011 - December 31, 2011	20,000 GJ/d	CDN \$5.20/GJ

Crude Oil:

Fixed Price:		
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN \$74.30/Bbl
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN \$76.50/Bbl
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN \$74.50/Bbl
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN \$77.00/Bbl
January 1, 2011 – December 31, 2011	500 Bbl/d	WTI CDN \$92.00/Bbl
January 1, 2011 – December 31, 2011	1,000/Bbl/d	WTI CDN \$84.15/Bbl
Costless Collars:		
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN \$75.00-\$94.00/Bbl
January 1, 2010 – December 31, 2010	500 Bbl/d	WTI CDN \$75.00-\$95.00/Bbl
January 1, 2011 – December 31, 2011	1,000 Bbl/d	WTI CDN \$77.10-\$90.00/Bbl
Other:		
January 1, 2012 – December 31, 2012	1,000 Bbl/d	WTI US \$85.00 Call
January 1, 2012 – December 31, 2012	1,100 Bbl/d	WTI US\$ 85.00 Swaption

Interest Rate Swap:

Notional Amount CAD \$100 million	Term: January 20, 2009 – January 20, 2011
Fixed rate 1.1% - Floating rate is reset against CAD--CDOR on each 3 month anniversary	

The Corporation has entered into the above contracts for the purpose of protecting funds generated from operations from the volatility of commodity prices and interest rates. The Corporation recognizes the fair value of its financial derivatives on the balance sheet each reporting period with the change in fair value recognized as an unrealized gain or loss on the statement of earnings. At September 30, 2010 the fair value is estimated to be a net asset of \$8.5 million, composed of a \$19.0 million short term asset, a \$3.7 million long-term asset, a \$3.1 million current liability, and an \$11.1 million long-term liability.

The fair value determinations for the Corporation's financial derivatives are based upon Level 3 inputs, having been provided by the counterparties with whom the transactions were completed and reviewed by the Corporation for reasonableness.

## 10. CAPITAL STRUCTURE FINANCIAL POLICIES

The Corporation's strategy is to maintain net debt to funds from operations at or below a level of 1.5 to 1. While the corporation may exceed this rate from time to time, variations are viewed as short term, and efforts are made after a period of variation to bring the measure back in line.

The Corporation's strategy concerning capitalization is to utilize more equity than debt. This is measured by targeting total debt to total debt plus shareholders' equity at a ratio of less than 0.4 to 1. The Corporation has no externally imposed capital requirements.

At September 30 (\$000s)	Target Measure	2010 \$	2009 \$
<b>Components of ratios</b>			
Current assets (excluding fair value of financial derivative and future income taxes)		32,599	35,582
Current liabilities (including short term debt and excluding fair value of financial derivative and future income taxes)		172,331	277,638
Net debt		139,732	242,056
Total debt (bank loan and capital leases)		122,283	232,731
Shareholders' equity (share capital plus retained earnings)		682,017	673,228
Total capitalization (total debt plus shareholders' equity)		804,300	905,959
Funds from operations <sup>1</sup> (nine months ended September 30 annualized)		105,668	99,431
Net debt/funds from operations	< 1.5 times	1.3	2.4
Total debt/total debt plus shareholders' equity	< 0.4 times	0.2	0.3

<sup>1</sup> Funds from operations is a non-GAAP measure and is based on cash flow from operating activities before changes in non-cash working capital and abandonment expenditures.

The decrease in the net debt to funds from operations ratio from 2009 to 2010 resulted primarily from the 47% decrease in net debt.

## 11. RESTRUCTURING COSTS

In March 2010 the Board of Directors initiated a process to identify and consider strategic alternatives, with a view to enhancing shareholder value. The strategic review process was completed in July 2010. In conjunction with the sale of assets in the Puskwa area of Alberta in the second quarter of 2010, the Corporation restructured its technical and operational teams. Expenses of \$1.2 million related to the restructuring process were incurred during the nine months ended September 30, 2010.

## 12. SUBSEQUENT EVENT

Subsequent to September 30, 2010, the Corporation entered into the following financial contracts:

Natural Gas:		
April 1, 2011 – December 31, 2011	5,000 GJ/d	CDN \$5.60/GJ
Crude Oil:		
January 1, 2012 – December 31, 2012	527 Bbl/d	WTI US \$85.00/Bbl Call

## 13. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current period's consolidated financial statement presentation.