

GALLEON ENERGY INC.

Management's Discussion and Analysis

June 30, 2010

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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 six month periods ended June 30, 2010 with comparisons to the three and six months ended June 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 six month periods ended June 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, August 12, 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), or at Galleon's website (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

(\$000s except per share and per unit amounts)	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Financial				
Revenue before royalties and financial derivatives	55,273	50,373	117,557	107,360
Funds flow from operations ¹	27,146	29,605	58,826	55,755
Per share – basic	0.32	0.39	0.69	0.74
Per share – diluted	0.32	0.39	0.69	0.74
Net income (loss)	2,328	(22,012)	14,819	(27,103)
Per share – basic	0.03	(0.29)	0.17	(0.36)
Per share – diluted	0.03	(0.29)	0.17	(0.36)
Capital expenditures – exploration & development	22,788	19,619	61,663	50,010
Total assets	1,010,855	1,141,506	1,010,855	1,141,506
Net debt ²	115,844	233,225	115,844	233,225
Shareholders' equity	726,190	700,400	726,190	700,400
Weighted average shares outstanding				
Basic	85,143,751	76,040,581	85,121,469	75,638,439
Diluted	85,143,751	76,040,581	85,121,469	75,638,439
Operating				
Average daily production				
Light oil (Bbl/d)	3,295	4,024	3,272	4,235
Heavy oil (Bbl/d)	1,108	1,198	1,135	1,212
NGLs (Bbl/d)	537	565	532	625
Natural gas (Mcf/d)	67,689	61,733	65,937	65,660
Total (BOE/d)	16,222	16,076	15,928	17,016
Average selling prices ³				
Light oil (\$/Bbl)	72.53	61.39	74.95	54.15
Heavy oil (\$/Bbl)	57.76	51.54	61.43	42.54
NGLs (\$/Bbl)	53.41	39.23	55.09	36.41
Natural gas (\$/Mcf)	4.07	3.61	4.63	4.41
Total (\$/BOE)	37.44	34.43	40.78	34.86

¹ See "Non-GAAP Measurements"

² Net debt includes bank indebtedness, working capital and capital leases, but excludes financial derivatives

³ The average prices reported are before realized derivatives and transportation charges

Solid financial and operations results were recorded in second quarter 2010. Average production of 16,222 BOE/d (70% natural gas and 30% oil and NGLs) generated revenues of \$55.3 million (\$0.65 per basic and diluted share) and funds flow from operations of \$27.1 million (\$0.32 per basic and diluted share). Operating expenses averaged \$9.03/BOE in second quarter 2010.

Galleon completed the sale of the majority of its interests in the Puskwa property on June 25, 2010 to Barrick Energy Inc. for cash proceeds of \$133.6 million. In late 2005, Galleon's technical team identified a potentially large light oil pool at Puskwa. In early 2006, the magnitude of the Puskwa asset was discovered with the success of the well drilled at 16-32-71-26W5. In the past four years, through a successful development program, including infill-drilling and the implementation of enhanced recovery projects, Galleon has grown the Puskwa asset, into one which has generated significant cash flow. The sale of the Puskwa property has placed Galleon in a strong financial position. The Corporation is well positioned to develop its existing properties, to identify new opportunities and to realize future value for shareholders.

Results of Operations

Comparative financial results for the quarter are as follows:

Three months ended June 30	2010		2009	
	1,476,256 BOE		1,462,922 BOE	
(\$000s)		\$/BOE		\$/BOE
Revenues	55,273	37.44	50,373	34.43
Realized gain on financial derivative	5,329	3.61	3,774	2.58
Other income	-	-	74	0.05
Royalties	(11,931)	(8.08)	(11,560)	(7.90)
GCA ¹	2,016	1.37	8,477	5.79
Transportation costs	(2,422)	(1.64)	(2,056)	(1.41)
Operating costs	(13,328)	(9.03)	(13,790)	(9.43)
Net	34,937	23.67	35,292	24.11
G&A	(3,063)	(2.07)	(3,827)	(2.62)
Restructuring costs	(1,183)	(0.81)	-	-
Interest costs	(3,578)	(2.42)	(1,702)	(1.16)
Capital and other taxes	33	0.02	(158)	(0.11)
Funds from operations²	27,146	18.39	29,605	20.22

Six months ended June 30	2010		2009	
	2,883,007 BOE		3,079,901 BOE	
(\$000s)		\$/BOE		\$/BOE
Revenues	117,557	40.78	107,360	34.86
Realized gain on financial derivative	6,764	2.35	8,111	2.63
Other income	-	-	746	0.24
Royalties	(27,212)	(9.44)	(27,137)	(8.81)
GCA ¹	6,615	2.29	13,702	4.45
Transportation costs	(4,611)	(1.60)	(4,398)	(1.43)
Operating costs	(25,815)	(8.95)	(31,087)	(10.09)
Net	73,298	25.43	67,297	21.85
G&A	(6,631)	(2.30)	(8,028)	(2.61)
Restructuring costs	(1,183)	(0.42)	-	-
Interest costs	(6,592)	(2.29)	(3,287)	(1.07)
Capital and other taxes	(66)	(0.02)	(227)	(0.07)
Funds from operations²	58,826	20.40	55,755	18.10

¹ GCA means Gas Cost Allowance

² See "Non-GAAP Measurements"

Petroleum and Natural Gas Revenues

Three months ended June 30	2010		2009	
(\$000s)		%		%
Light oil	21,688	39	22,448	45
Heavy oil	5,836	11	5,604	11
NGLs	2,611	5	2,017	4
Natural gas	24,988	45	20,197	40
Royalty income	150	-	107	-
Total	55,273	100	50,373	100

Six months ended June 30	2010		2009	
(\$000s)		%		%
Light oil	44,251	38	41,388	39
Heavy oil	12,620	11	9,316	8
NGLs	5,304	5	4,122	4
Natural gas	55,076	46	52,204	49
Royalty income	306	-	330	-
Total	117,557	100	107,360	100

Revenues for the three months ended June 30, 2010 increased by 10% to \$55.3 million from \$50.4 million for the same period in 2009. The increase is primarily due to a 10% increase in natural gas production and a 13% increase in natural gas prices. Increased revenue from higher oil prices in Q2 2010 was offset by the decline in oil production volumes.

Production

	Three months ended June 30				Six months ended June 30			
	2010		2009		2010		2009	
		%		%		%		%
Light oil (Bbls/d)	3,295	20	4,024	25	3,272	21	4,235	25
Heavy oil (Bbls/d)	1,108	7	1,198	8	1,135	7	1,212	7
NGLs (Bbls/d)	537	3	565	3	532	3	625	4
Natural gas (Mcf/d)	67,689	70	61,733	64	65,937	69	65,660	64
BOE/d (6:1)	16,222	100	16,076	100	15,928	100	17,016	100

Average production was 16,222 BOE/d for the second quarter of 2010, 1% higher than the average production of 16,076 BOE/d for the second quarter of 2009. Daily production volumes varied by product as follows: light oil decreased by 18%; heavy oil decreased by 8%; natural gas increased by 10% and natural gas liquids decreased by 5%.

Production in Q2 2010 increased by 591 BOE/d from 15,631 BOE/d in Q1 2010. This 4% increase was due primarily to new production coming on-stream from properties in the North Peace River Arch area.

Excluding Puskwa, production for the three months ended June 30, 2010 was 14,739 BOE/d, compared to 13,845 BOE/d during the three months ended June 30, 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 had the following financial contracts in place as at June 30, 2010:

Natural Gas:		
January 1, 2010 to December 31, 2011	5,000 GJ/d	CDN \$5.75/GJ
January 1, 2010 to December 31, 2011	5,000 GJ/d	CDN \$5.85/GJ
April 1, 2010 to March 31, 2011	5,000 GJ/d	CDN \$5.76/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 \$74.50/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 \$77.00/Bbl
January 1, 2011 – December 31, 2011	500 Bbl/d	WTI CDN \$92.00/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
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 second quarter of 2010, Galleon recorded realized gains of \$5.3 million on these financial contracts, compared to a \$3.8 million gain realized in the second quarter of 2009. The Q2 2010 gain included net proceeds of \$2.7 million received on the unwinding of a 5,000 GJ/d natural gas contract for \$5.75/GJ and two oil contracts of 500 Bbls/d each, at \$76.25/Bbl and \$77.00/Bbl respectively. The contracts had original terms from January 1, 2010 to December 31, 2011.

Based on the mark to market value at June 30, 2010, an unrealized loss on financial contracts of \$1.0 million was recorded in the second quarter of 2010, compared to an unrealized loss of \$25.0 million in Q2 2009.

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

	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Light oil (\$/Bbl)	72.53	61.39	74.95	54.15
Heavy oil (\$/Bbl)	57.76	51.54	61.43	42.54
NGLs (\$/Bbl)	53.41	39.23	55.09	36.41
Natural gas (\$/Mcf)	4.07	3.61	4.63	4.41

Comparing the three month period ended June 30, 2010 to 2009, the light oil price increased by 18%, the heavy oil price increased by 12%, the NGL price increased by 36% and the natural gas price increased by 13%.

Crude Oil Prices

Three months ended June 30	2010		2009	
	\$000s	\$/Bbl	\$000s	\$/Bbl
Crude oil	27,577	68.82	28,101	59.13
Realized financial contracts	(1,005)	(2.51)	(738)	(1.55)
Transportation	(550)	(1.37)	(545)	(1.15)
Net crude oil	26,022	64.94	26,818	56.43

Six months ended June 30	2010		2009	
	\$000s	\$/Bbl	\$000s	\$/Bbl
Crude oil	57,014	71.48	50,841	51.57
Realized financial contracts	(1,185)	(1.49)	(521)	(0.53)
Transportation	(942)	(1.18)	(1,101)	(1.12)
Net crude oil	54,887	68.81	49,219	49.92

Natural Gas Prices

Three months ended June 30	2010		2009	
	\$000s	\$/Mcf	\$000s	\$/Mcf
Natural gas	25,086	4.07	20,255	3.61
Realized financial contracts	6,451	1.05	4,599	0.82
Transportation	(1,872)	(0.30)	(1,511)	(0.27)
Net natural gas	29,665	4.82	23,343	4.16

Six months ended June 30	2010		2009	
	\$000s	\$/Mcf	\$000s	\$/Mcf
Natural gas	55,239	4.63	52,397	4.41
Realized financial contracts	8,226	0.69	8,720	0.73
Transportation	(3,668)	(0.31)	(3,297)	(0.28)
Net natural gas	59,797	5.01	57,820	4.86

Performance by Property

	2010			2009			2010 Funds from operations ²
	Production		Operating netbacks/ BOE ¹	Production		Operating netbacks/ BOE ¹	
	BOE/d	%		BOE/d	%		
Eastern Montney	4,588	28	15.86	4,118	26	13.18	24
Kakut	3,599	22	18.81	2,484	15	12.88	22
Puskwa	1,483	9	34.14	2,231	14	29.74	17
Eaglesham	1,354	8	17.99	2,335	15	18.74	8
Alexis / St.Anne	1,135	7	21.88	1,034	6	4.40	8
Culp /Kimiwan	884	6	25.81	642	4	21.60	7
Edam	514	3	22.09	578	4	23.42	4
Other	2,665	17	11.12	2,654	16	9.23	10
	16,222	100	18.75	16,076	100	15.73	100

Six months ended June 30

	2010			2009			2010 Funds from operations ²
	Production		Operating netbacks/ BOE ¹	Production		Operating netbacks/ BOE ¹	
	BOE/d	%	\$	BOE/d	%	\$	
Eastern Montney	4,508	28	18.28	4,278	25	14.00	25
Kakut	3,644	23	19.95	2,490	15	14.92	22
Puskwa	1,503	10	36.84	2,313	14	27.06	17
Eaglesham	1,434	9	19.10	2,680	16	17.52	8
Alexis / St.Anne	1,129	7	22.22	1,038	6	6.61	8
Culp /Kimiwan	746	5	26.84	671	4	16.72	6
Edam	538	3	25.50	594	3	9.55	4
Other	2,426	15	13.86	2,952	17	5.89	10
	15,928	100	20.74	17,016	100	14.56	100

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

² See "Non-GAAP Measurements"

Eastern Montney production averaged 4,588 BOE/d (89% natural gas and 11% oil and NGLs) during Q2 2010 which was 11% higher than average production during Q2 2009. The Eastern Montney natural gas project continues to represent a significant resource to Galleon and is still the largest producing area, contributing 24% to total funds from operating activities in Q2 2010 based on 28% of production volumes.

The Kakut property continues to be a significant growth area for Galleon. Production for Q2 2010 averaged 3,599 BOE/d (90% natural gas and 10% oil and NGLs) which represents an increase of 45% from Q2 2009. The Kakut property contributed 22% of total funds from operating activities based on 22% of production volumes in Q2 2010. Galleon is currently in the process of expanding the Kakut oil battery in anticipation of continued growth in both oil and gas production. This expansion is expected to be completed in the second half of 2010.

The majority of the Puskwa property was sold to a third party on June 25, 2010. Production of 1,483 BOE/d was included in Q2 2010 results which represented a decrease of 34% from Q2 2009. In Q2 2010, Puskwa contributed 17% of funds from operations from 9% of production volumes.

Production at Eaglesham in Q2 2010 averaged 1,354 BOE/d (69% natural gas and 31% oil and NGLs), which was a decrease of 42% from Q2 2009. In Q2 2010, Eaglesham contributed 8% of the funds from operations and 8% of production volumes.

The Alexis/St. Anne properties generated 8% of funds from operations from 7% of total production for Q2 2010. Average production of 1,135 BOE/d (65% oil and NGLs and 35% natural gas) was recorded in Q2 2010, an increase of 10% from Q2 2009.

The Culp/Kimiwan light oil properties contributed 7% of funds from operations in Q2 2010 based on 6% of production volumes. Average production was 884 BOE/d (68% oil and NGLs and 32% natural gas) in Q2 2010, an increase of 38% from Q2 2009.

The Edam oil properties produced 514 Bbl/d in Q2 2010, a decrease of 11% from Q2 2009. These heavy oil wells generated 4% of funds from operations from 3% of total production based on the strength of high netbacks associated with low heavy oil differentials.

Galleon has emerged from the strategic review process with a four part operational and financial plan, which included reorganizing the Corporation's technical and operational teams on a business unit basis. The Corporation has been restructured into three business units: Eastern Montney, North Peace River Arch and Kakut.

Eastern Montney Business Unit – Comprised of Eastern Montney and Culp/Kimiwan

Production results to date have continued to meet Galleon's expectations. Over the past 3 years of development of the Eastern Montney project, Galleon has continuously added production resulting in a solid base. To date, Galleon has drilled a total of 52 horizontal wells and 83 vertical wells in the project area. The project area encompasses a fairway that extends 30 miles long and 10 miles wide that has been mapped and tested. Galleon has identified over 350 horizontal drilling locations based on 4 wells per section on its land. The goal in 2010 is to increase the proven producing reserves by drilling the large existing drilling inventory.

A total of seven (7.0 net) Eastern Montney horizontal wells were drilled in Q2 2010. All of these wells have been placed on production with, on average, daily production exceeding 750 Mcf per well in the first month of production. Galleon plans to continue to develop the Montney to operate at maximum facility capacity. Currently, the facilities are restricting sales to 4,700 BOE/d. The drilling of up to 8 additional development Montney horizontal wells in the second half of 2010 is expected to offset production declines. Capital expenditures of approximately \$11 million are planned in the second half of 2010.

The Eastern Montney project continues to provide low risk locations with continued repeatability resulting in high drilling success. On a per well basis this project continues to deliver low cost production (\$1.3 million on average to drill, complete and tie-in each well) with high liquid yield gas (on average 17 barrels per 1 million cubic feet) therefore allowing this project to continue to be economic within the current low gas price environment of approximately \$3.65/Mcf AECO.

North Peace River Arch Business Unit ("NPRA") – Comprised of Eaglesham, Alexis/St. Anne, Puskwa and Other

In this business unit, Galleon has three new projects targeting light oil and one new project targeting natural gas with horizontal drilling technology. Capital expenditures of approximately \$15 million are planned in the second half of 2010 including the drilling of up to 14 wells.

In Q2 2010, Galleon drilled 1 (1.0 net) Montney horizontal gas well in the NPRA. The cost to drill and complete this well was \$1.3 million. The well has produced approximately 750 Mcf/d on average over the first 3 months of production. This is the initial well in the 2010 NPRA drilling program that will target low permeability Montney sands at depths of approximately 1,000 metres (total vertical depth).

Many of the locations will target Montney oil in plays that are analogous to the Grimshaw Triassic D pool which has seen substantial horizontal drilling activity over the past year. Based on public data, the initial average production of these wells has been approximately 100 BOE/d.

One horizontal oil well is planned at Grimshaw in Q3 2010 on a play that immediately offsets the Grimshaw Triassic D pool. This play was defined by 3D seismic and 2 vertical wells have confirmed the zone. Although at an early stage Galleon anticipates drilling follow up wells in Q4 2010. The Grimshaw Triassic D pool is currently being developed on 4 wells per section.

The Flood Montney C oil pool is a defined Montney pool of approximately 2 sections (65% interest) in size. Current development is through vertical wells. Galleon plans to drill at least two horizontal multi-stage fracture development oil wells into this pool in the second half of 2010. These wells will be drilled in undrilled spacing units and will offset vertical oil wells that had an initial gross production rate of 50 Bbl/d and stabilized at a gross rate of 20 Bbl/d. The production rates for horizontal multi-stage fracture wells are

anticipated to be 2 to 3 times higher than the rates from vertical wells. A holding is in place for 2 wells per quarter section which allows for a number of low risk development locations. Additional development wells are planned to be drilled in 2011. This project represents a low risk opportunity to add light oil production and reserves.

Up to 4 additional Montney wells are planned in the NPRA during the second half of 2010. Galleon also plans to target medium depth liquid rich gas in the Berwyn and Whitelaw areas.

Kakut Business Unit – Comprised of Kakut and Edam

The development plan for the Kakut Doig light oil/natural gas resource project is proceeding as planned. Drilling has confirmed a productive fairway of at least 15 miles in length. Galleon expects to have the Kakut battery expansion completed by September 1, 2010. The expansion will increase fluid handling capacity from 1,000 to 10,000 barrels per day. The Kakut gas plant capacity is 28 Mmcf/d and is currently processing approximately 18 Mmcf/d.

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. The pay zone has good porosity. The zone has relatively low permeability such that it is similar to other plays such as the Bakken and Cardium in which horizontal wells with multi-stage fracturing technology have been very successful.

Galleon drilled its first horizontal well at Kakut in late 2008. The well was drilled with only a short horizontal length of 400 metres to test the concept and to control costs. The well successfully proved the viability of the application of horizontal well with multi-stage fracturing technology to exploit the resource.

The 2009 drilling program focused on optimizing well productivity and capturing reserves. Based on the results to date, Galleon has seen that the optimal length of the horizontal lateral is approximately 1,200 metres with 100 metre fracture spacing and 3 tonnes fracture stimulation per stage. The improvement in the design of the length, fracture spacing and fracture size has resulted in well productivity increases of between 50 and 100 percent compared to the early short horizontal wells. The total well costs have increased by only 10 to 15 percent.

Galleon has drilled 11 (10.6 net) Doig horizontal wells to date at Kakut. Three of the wells were delineation wells that tested hydrocarbons but have not been tied in. One well is being equipped for production and the remaining 7 wells have produced to the Kakut battery. At June 30, 2010, net production from the project reached 1,437 BOE/d including 427 Bbl/d of oil.

After June 30, 2010, 2 wells (100% interest) which were producing approximately 900 BOE/d (83% natural gas and 17% oil and NGLs) were shut in after the 4 month new oil production period came to an end. The well located at 16-6-75-3W6M produced 12,750 barrels of oil and 0.227 BCF (average of 420 BOE/d) to June 30, 2010. The well located at 4-28-74-3W6M produced 5,530 barrels of oil and 0.368 BCF (average of 550 BOE/d) to June 30, 2010. Galleon is in the process of composing applications for these 2 wells which could result in the two wells being placed back on production at optimal rates. No other Doig producing wells are required to be shut in as their gas production is below the ERCB determined maximum rate limit.

Galleon has received a down spacing approval for 4 horizontal wells per section on 4 sections of land. Application for down spacing to include another 7 sections of land is underway.

Capital expenditures of approximately \$48 million are planned at Kakut in the second half of 2010. Galleon expects to drill up to 17 Doig horizontal wells in the second half of 2010 including 4 delineation step-out wells. The step-out wells are expected to further confirm the 15 mile fairway and further de-risk the extension of the fairway. Galleon currently has access to 53 sections (83% interest) of land in this fairway.

Other

Galleon intends to actively farm out opportunities on its 810,000 net acres of land. These activities combined with its exposure to the emerging Nordegg, Duverney and Slave Point resource plays may lead to value enhancement in the next 12 to 24 months.

Royalties

Three months ended June 30	2010	2009
(\$000s, except as indicated)		
Crown	10,285	9,765
Freehold	735	602
GORR and other	911	1,193
Gross royalties	11,931	11,560
GCA	(2,016)	(8,477)
Net royalties	9,915	3,083
% of revenue	21.6	23.0
% of revenue net of GCA	17.9	6.1
Six months ended June 30	2010	2009
(\$000s, except as indicated)		
Crown	22,516	23,603
Freehold	2,401	1,249
GORR and other	2,295	2,285
Gross royalties	27,212	27,137
GCA	(6,615)	(13,702)
Net royalties	20,597	13,435
% of revenue	23.1	25.3
% of revenue net of GCA	17.5	12.5

Gross royalties were 21.6% for the second quarter of 2010 compared to 23% for the same period in 2009. By product the royalty rates were 21.7% for heavy oil, 30.7% for light oil, 13.0% for natural gas and 27.7% for liquids for Q2 2010. For the second quarter of 2009, the royalty rates were 22.6% for heavy oil, 24.3% for light oil, 18.9% for natural gas and 43.0% for liquids.

Net royalties were 17.9% for the second quarter of 2010 compared to 6.1% for the same period in 2009. Q2 2009 net royalties included 2008 GCA adjustments of \$4.5 million.

The lower gas royalty rate in the second quarter of 2010 compared to Q2 2009 was mainly due to the royalty rate reductions applicable to the first 12 months of new production coming on-stream in Alberta from April 1, 2009. Oil royalties in Q2 2010 included the reversal of a \$1.0 million prior year Crown royalty holiday.

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 June 30, 2010, the Corporation had recorded drilling credits of \$18.9 million as reduction of property and equipment.

Operating Costs

Three months ended June 30	2010			2009		
	Production	Operating Costs		Production	Operating Costs	
	%	%	\$/BOE	%	%	\$/BOE
Eastern Montney	28	23	7.50	26	21	7.68
Kakut	22	13	5.35	15	6	3.41
Puskwa	9	4	4.02	14	8	5.16
Eaglesham	8	10	10.44	15	8	5.13
Alexis / St.Anne	7	10	12.42	6	15	21.97
Culp /Kimiwan	6	9	15.60	4	7	17.40
Edam	3	6	16.57	4	6	16.69
Other	17	25	13.61	16	29	16.75
	100	100	9.03	100	100	9.43

Six months ended June 30	2010			2009		
	Production	Operating Costs		Production	Operating Costs	
	%	%	\$/BOE	%	%	\$/BOE
Eastern Montney	28	22	6.84	25	18	7.39
Kakut	23	12	4.60	15	5	3.78
Puskwa	10	5	4.88	14	6	4.55
Eaglesham	9	11	11.34	16	10	6.21
Alexis / St.Anne	7	10	12.82	6	11	18.57
Culp /Kimiwan	5	9	17.87	4	8	21.23
Edam	3	6	16.43	3	8	22.66
Other	15	25	14.33	17	34	19.17
	100	100	8.95	100	100	10.09

Operating costs were \$13.3 million or \$9.03/BOE for the second quarter of 2010 compared to \$13.8 million or \$9.43/BOE for the same period of the prior year. This represents a decrease year over year of 4% on a per unit basis. Operating expenses on Galleon's four major properties averaged \$6.69/BOE in the three months ended June 30, 2010, comprising 67% of total production. Excluding Puskwa, operating expenses on the remaining three major properties averaged \$7.11/BOE in the three months ended June 30, 2010, comprising 65% of total production after removing the Puskwa volumes.

In the Eastern Montney natural gas project, operating costs were \$7.50/BOE in Q2 2010, a 2% decrease from \$7.68/BOE in Q2 2009. Eastern Montney is one of Galleon's low cost producing properties.

Operating costs at Kakut were \$5.35/BOE in Q2 2010, an increase of 57% from \$3.41/BOE in the same period prior year. Costs were higher in Q2 2010 due to field sweetening for gas and increased compressor maintenance costs related to two additional compressors installed in Q3 2009 with the gas plant expansion.

Operating costs at Puskwa were \$4.02/BOE in second quarter 2010 compared to \$5.16/BOE in the same period of 2009. The decrease in operating costs was mainly due to lower water pump injection maintenance in the second quarter of 2010.

Eaglesham operating costs for Q2 2010 were \$10.44/BOE, an increase of 104% from \$5.13/BOE in second quarter 2009. Lower equipment rental and propane and fuel costs in the second quarter of 2010, resulting from the electrification of wells and the plant, were offset by decreased production volumes.

General and Administration Expenses

Three months ended June 30	2010		2009	
(\$000s)		\$/BOE		\$/BOE
Gross	4,388	2.97	4,988	3.41
Capitalized overhead	(636)	(0.43)	(657)	(0.45)
Overhead recoveries	(689)	(0.47)	(504)	(0.34)
Net	3,063	2.07	3,827	2.62

Six months ended June 30	2010		2009	
(\$000s)		\$/BOE		\$/BOE
Gross	9,181	3.18	10,492	3.41
Capitalized overhead	(1,494)	(0.52)	(1,455)	(0.47)
Overhead recoveries	(1,056)	(0.36)	(1,009)	(0.33)
Net	6,631	2.30	8,028	2.61

Gross G&A expenses decreased by \$600,000 or 12% in Q2 2010 from Q2 2009, due primarily to lower office and administration expenses.

For the three months ended June 30, 2010 G&A expenses by category were: salary and employee – 60%, office – 20%, consulting – 6%, computer – 6%, shareholder costs – 2%, audit, engineering and legal – 3%, and corporate – 3%.

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 net cash consideration of \$130.9 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 Q2 2010.

Interest

Interest expense of \$3.6 million for the three months ended June 30, 2010 was 112% higher than the \$1.7 million recorded in the same period of the prior year. A lower average debt balance outstanding during Q2 2010 was more than offset by a 3.5% higher effective interest rate.

At June 30, 2010 an amount of \$111.7 million was drawn against the Corporation's credit facility, compared to \$235.8 million at June 30, 2009.

Stock Based Compensation

Stock based compensation was a non-cash expense of \$1.3 million for the second quarter of 2010, consistent with the \$1.3 million recorded in the same quarter of the prior year.

During the second quarter of 2010, no stock options were granted to employees. At June 30, 2010, 6,999,834 stock options were outstanding at an average exercise price of \$6.04 per share.

Depletion, Depreciation and Accretion

For the three months ended June 30, 2010, depletion and depreciation totaled \$32.8 million (\$22.21/BOE), as compared to \$32.3 million (\$22.05/BOE) for the same period in the prior year. Reserve additions for the second quarter of 2010 were estimated internally.

Capital expenditures of \$60.3 million (June 30, 2009 - \$103.9 million) related to undeveloped land and seismic have been excluded from the depletion and depreciation calculation, and \$158.7 million (June 30, 2010 - 164.1 million) of future development costs have been added.

Accretion expense on the Corporation's asset retirement obligation was \$723,000 for the second quarter of 2010, compared to \$664,000 in the second quarter of 2009.

Capital and Future Taxes

The current tax recovery of \$33,000 (June 30, 2009 - \$158,000 expense) 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 \$15.7 million was recorded in Q2 2010 on a loss before tax of \$13.4 million. An income tax recovery of \$7.6 million on a loss before tax of \$29.5 million was recorded in 2009. The Q2 2010 income tax recovery includes a \$12.7 million benefit relating to the disposition of properties.

Capital Expenditures

	(\$000s)
Property & equipment balance at December 31, 2009	1,041,140
Additions to property and equipment	61,663
Dispositions of property and equipment	(130,912)
Acquisition of property and equipment	16,966
Asset retirement obligation additions	150
Asset retirement obligation disposed	(1,839)
Depletion and depreciation	(63,524)
Property & equipment balance at June 30, 2010	923,644

Three months ended June 30	2010		2009	
(\$000s)		%		%
Land	1,477	7	581	3
Geological and geophysical	249	1	344	2
Drilling and completion	16,916	74	10,856	55
Plant and facilities	4,146	18	7,769	40
Other assets	-	-	69	-
Exploration and development expenditures	22,788	100	19,619	100

Six months ended June 30	2010		2009	
(\$000s)		%		%
Land	4,174	7	1,359	3
Geological and geophysical	531	1	1,399	3
Drilling and completion	46,676	76	32,401	65
Plant and facilities	10,251	16	14,738	29
Other assets	31	-	113	-
Exploration and development expenditures	61,663	100	50,010	100

Exploration and development expenditures during the second quarter of 2010 were \$22.8 million. Drilling and completion expenditures comprised 74% of exploration and development activity. Galleon drilled 14 (13.5 net) wells resulting in 9 (8.5 net) natural gas wells and 4 (4.0 net) oil wells, for a success rate of 93% for the quarter.

Facilities expenditures were \$4.1 million in Q2 2010 or 18% of total expenditures. Land and seismic expenditures totaled \$1.5 million and \$0.2 million, respectively, in the second quarter 2010.

During the three months ended June 30, 2010 the Corporation sold properties in the Puskwa area of Alberta for net cash consideration of \$130.9 million, as part of the strategic review process completed in July 2010. 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.

Liquidity and Capital Resources

As at June 30	2010	2009
(\$000s)		
Bank debt	111,719	235,829
Capital leases – non current	-	1,135
Working capital deficiency ¹	4,125	(3,739)
Total net debt	115,844	233,225

¹ Excludes future income taxes and fair value of financial derivatives

Funding of Capital Program

Three months ended June 30	2010	2009
(\$000s)		
Issuance of shares, net of costs	56	34,489
Funds from operations	27,146	29,605
Change in bank debt	(117,832)	(27,790)
Change in capital leases	(207)	(202)
Acquisition of properties	-	-
Disposition of properties	130,912	4,633
Change in inventory	1,070	1,896
Change in working capital and other	(18,357)	(23,012)
	22,788	19,619

Six months ended June 30	2010	2009
(\$000s)		
Issuance of shares, net of costs	268	34,947
Funds from operations	58,826	55,755
Change in bank debt	(105,524)	(13,186)
Change in capital leases	(410)	(406)
Acquisition of properties	(16,966)	-
Disposition of properties	130,912	4,633
Change in inventory	(101)	4,420
Change in working capital and other	(5,342)	(36,153)
	61,663	50,010

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, excluding the capital leases. At June 30, 2010, an amount of \$111.7 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 June 30, 2010, the effective interest rates were 6.1% and 5.8%, respectively (June 30, 2009 – 2.6% and 2.5%).

Commitments

Office Lease Payments

At June 30, 2010 the Corporation is committed to \$0.6 million in future minimum payments under operating leases for office space in 2010.

Subsequent to June 30, 2010 the Corporation committed to future minimum lease payments under an operating lease for office space with future minimum lease payments 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.

Capital Lease

The Corporation has an equipment lease financing arrangement with annual minimum lease payments of \$1.2 million remaining in 2010. The lease has an interest rate of 6.3 percent and the equipment purchase price at the end of the lease on September 1, 2010 is \$1.0 million. A general security agreement and a first charge against the equipment have been provided as collateral.

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 June 30, 2010, \$12.2 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 is in progress.

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 has completed analysis required to compile the opening IFRS balance sheet amounts.

Audit work on the opening balance sheet is expected to be completed during the fourth quarter of 2010. The Corporation’s plans include preparation of the IFRS based comparative statements for each of the quarters ended in 2010 following completion of the opening 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 June 30:

	2010	2009
Class A shares outstanding		
Basic	85,147,883	82,890,883
Diluted ¹	85,147,883	82,890,883

¹ Includes no options (June 30, 2009 – nil)

At June 30, 2010, the market value of Galleon's Class A shares was \$367.0 million based on the closing price of \$4.31 per share. As of August 12, 2010, the number of Class A shares and options outstanding are 85,147,883 and 5,959,501 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, or from the Corporation's website at www.galleonenergy.com.

Outlook

In July, 2010, Galleon announced that the special committee of the Board of Directors had completed its strategic review process. During the strategic review process, the Board of Directors and management engaged in an exhaustive examination of the Corporation's assets and opportunities to identify strengths, weaknesses and opportunities, and to address each in turn. Galleon has emerged from the strategic review process with a four part operational and financial plan.

- To increase balance sheet strength to give the Corporation the flexibility to execute the operational plan. This has been accomplished through the previously announced asset sale of Puskwa resulting in net debt of below \$120 million (approximately one times 2010 cash flow) and available credit facilities of \$250 million. The Corporation will continue to look at non-core asset dispositions to further enhance financial flexibility.
- To adopt a goal of significantly increasing the proportion of total reserves which are proven and proven developed producing. This entails concentrating our capital resources on drilling lands to which proven and probable undeveloped reserves have been assigned and converting those reserves into production and cash flow. The capital budget (approximately \$77 million net of drilling credits) for the remainder of 2010 is allocated 80% towards low risk development locations in our core producing areas. This program is targeted at reducing operational risk and improving production consistency.
- To adopt a strategy of farming out lands some of which are prospective for emerging resource plays, including those in the Nordegg, Duvernay and Slave Point. The goal will be to have third parties fund and prove up

the potential of our lands while retaining a significant portion of the net resource. A number of opportunities have been identified on our 810,000 net acres of land.

- To reorganize our technical and operational teams on a business unit basis. The Corporation has been restructured into three business units: Eastern Montney, North Peace River Arch and Kakut.

Production, net of certain contemplated minor asset sales, is expected to average over 14,000 BOE/d in the second half of 2010. This daily production estimate factors in downtime for major natural gas plant maintenance at Eastern Montney and Eaglesham, delays related to the Kakut oil battery expansion and the shut in of significant production at Kakut pending receipt of regulatory approvals.

Year end production is forecast to range between 14,000 BOE/d and 14,500 BOE/d of which 25-30% will be crude oil and natural gas liquids. This forecast excludes approximately 900 BOE/d of shut in production at Kakut due to the timing of regulatory approvals.

Year end net debt is expected to be approximately \$125 million, with forecasted operating costs in the second half of 2010 to be less than \$10.00/BOE. Planned 2011 capital expenditures are not expected to exceed cash flow.

Quarterly Highlights	2010				2009			2008
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Production								
Light oil (Bbl/d)	3,295	3,249	3,364	3,872	4,024	4,447	5,199	4,861
Heavy oil (Bbl/d)	1,108	1,161	1,210	1,281	1,198	1,227	1,338	1,618
Natural Gas (Mcf/d)	67,689	64,165	57,752	57,012	61,733	69,632	67,875	61,329
Liquids (Bbl/d)	537	527	489	561	565	687	604	499
BOE/d	16,222	15,631	14,688	15,216	16,076	17,965	18,453	17,200
Total BOE produced	1,476,256	1,406,752	1,351,338	1,399,847	1,462,922	1,616,979	1,697,711	1,582,369
Daily BOE of production per million Class A shares – basic	191	184	174	184	211	239	250	236
Prices (prior to realized gains or losses on financial contracts and prior to transportation)								
Light oil (\$/Bbl)	72.53	77.47	72.88	67.12	61.39	47.53	61.69	118.51
Heavy oil (\$/Bbl)	57.76	64.91	62.23	57.27	51.54	33.65	39.36	96.48
Crude oil (\$/Bbl)	68.82	74.17	70.06	64.67	59.13	44.53	57.12	113.01
Natural Gas (\$/Mcf)	4.07	5.22	4.60	3.16	3.61	5.13	6.97	8.00
NGLs (\$/Bbl)	53.41	56.80	52.06	43.87	39.23	34.07	42.76	73.16
Per BOE (\$)								
Revenues	37.44	44.28	41.65	35.36	34.43	35.24	47.29	73.20
Royalties, net of GCA	(6.71)	(7.59)	(6.91)	(7.10)	(2.11)	(6.40)	(6.51)	(13.13)
Transportation costs	(1.64)	(1.56)	(1.33)	(1.41)	(1.41)	(1.45)	(1.39)	(1.35)
Operating costs	(9.03)	(8.88)	(9.31)	(9.32)	(9.43)	(10.70)	(12.20)	(11.95)
Net	20.06	26.25	24.10	17.53	21.48	16.69	27.19	46.77
Other revenue	-	-	-	-	0.05	0.42	0.06	0.07
G&A	(2.07)	(2.54)	(3.28)	(2.47)	(2.62)	(2.60)	(2.37)	(2.05)
Restructuring costs	(0.81)	-	-	-	-	-	-	-
Interest	(2.42)	(2.14)	(2.27)	(2.05)	(1.16)	(0.98)	(1.53)	(1.74)
Capital and other taxes	0.02	(0.07)	(0.07)	(0.07)	(0.11)	(0.04)	(0.05)	(0.18)
Realized gain (loss) on financial derivative	3.61	1.02	(1.60)	0.50	2.58	2.68	15.78	(6.00)
Funds from operations¹	18.39	22.52	16.88	13.44	20.22	16.17	39.08	36.87

¹See "Non-GAAP Measurements"

Quarterly Highlights (unaudited)	2010			2009
	Q2	Q1	Q4	Q3
Financial (\$000s)				
Revenues	55,273	62,284	56,287	49,497
Operating costs	(13,328)	(12,487)	(12,582)	(13,045)
General & administrative expenses	(3,063)	(3,568)	(4,430)	(3,453)
Restructuring costs	(1,183)	-	-	-
Interest expense	(3,578)	(3,014)	(3,063)	(2,876)
Funds from operations¹	27,146	31,680	22,820	18,818
Per share, basic ¹	0.32	0.37	0.27	0.23
Per share, diluted ¹	0.32	0.37	0.27	0.23
Earnings (loss)	2,328	12,491	(5,654)	(1,815)
Per share, basic	0.03	0.15	(0.07)	(0.02)
Per share, diluted	0.03	0.15	(0.07)	(0.02)
Total assets	1,010,855	1,175,832	1,136,732	1,127,665
Weighted average outstanding Class A shares-basic	85,143,751	85,098,939	84,325,666	82,890,883
Weighted average outstanding Class A shares-diluted	85,143,751	85,098,939	84,325,666	82,890,883

Quarterly Highlights (unaudited)	2009			2008
	Q2	Q1	Q4	Q3
Financial (\$000s)				
Revenues	50,373	56,987	80,280	115,835
Operating costs	(13,790)	(17,297)	(20,704)	(18,917)
General & administrative expenses	(3,827)	(4,201)	(4,019)	(3,238)
Restructuring costs	-	-	-	-
Interest expense	(1,702)	(1,585)	(2,599)	(2,759)
Funds from operations¹	29,605	26,150	66,365	58,331
Per share, basic ¹	0.39	0.35	0.90	0.80
Per share, diluted ¹	0.39	0.35	0.90	0.79
Earnings (loss)	(22,012)	(5,091)	25,113	38,061
Per share, basic	(0.29)	(0.07)	0.34	0.52
Per share, diluted	(0.29)	(0.07)	0.34	0.51
Total assets	1,141,506	1,158,329	1,181,003	1,121,339
Weighted average outstanding Class A shares-basic	76,040,581	75,231,828	73,710,516	72,938,357
Weighted average outstanding Class A shares-diluted	76,040,581	75,231,828	74,032,935	73,955,365

¹ See "Non-GAAP Measurements"

GALLEON ENERGY INC.

**Financial Statements
(unaudited)**

JUNE 30, 2010

GALLEON ENERGY INC.
Consolidated Balance Sheets

(\$000s) (unaudited)	June 30, 2010	December 31, 2009
ASSETS		
CURRENT		
Accounts receivable	34,510	41,270
Deposits and prepaid expenses	5,810	6,190
Future income taxes (note 8)	-	2,884
Fair value of financial derivatives (note 10)	8,301	4,241
	<u>48,621</u>	<u>54,585</u>
Goodwill (note 3)	30,155	34,891
Fair value of financial derivatives (note 10)	2,218	
Equipment inventory	6,217	6,116
Property and equipment (notes 3, 4, 5, and 6)	923,644	1,041,140
	<u>1,010,855</u>	<u>1,136,732</u>
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	43,310	55,531
Capital leases (notes 3 and 6)	1,135	1,545
Future income taxes (note 8)	1,216	-
Bank loan (note 5)	111,719	217,243
Fair value of financial derivatives (note 10)	2,490	13,789
	<u>159,870</u>	<u>288,108</u>
Asset retirement obligation (note 4)	40,986	41,499
Future income taxes (note 8)	83,809	94,262
	<u>284,665</u>	<u>423,869</u>
SHAREHOLDERS' EQUITY		
Share capital (note 7)	595,239	599,334
Contributed surplus (note 7)	31,487	28,884
Retained earnings	99,464	84,645
	<u>726,190</u>	<u>712,863</u>
	<u>1,010,855</u>	<u>1,136,732</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 June 30		Six months ended June 30	
	2010	2009	2010	2009
REVENUE				
Petroleum and natural gas revenue	55,273	50,373	117,557	107,360
Royalties, net of GCA	(9,915)	(3,083)	(20,597)	(13,435)
Realized gain on financial derivative (note 10)	5,329	3,774	6,764	8,111
Unrealized gain (loss) on financial derivative (note 10)	(952)	(24,999)	17,577	(20,308)
Other income	-	74	-	746
	49,735	26,139	121,301	82,474
EXPENSES				
Operating	13,328	13,790	25,815	31,087
Transportation	2,422	2,056	4,611	4,398
General and administration	3,063	3,827	6,631	8,028
Restructuring costs (note 12)	1,183	-	1,183	-
Goodwill allocated to disposed properties (note 3)	4,736	-	4,736	-
Interest	3,578	1,702	6,592	3,287
Stock-based compensation (note 7)	1,324	1,290	2,702	2,569
Accretion	723	664	1,437	1,323
Depletion and depreciation	32,793	32,259	63,524	67,789
	63,150	55,588	117,231	118,481
Earnings (loss) before taxes	(13,415)	(29,449)	4,070	(36,007)
Income taxes (note 8)				
Capital and other taxes	(33)	158	66	227
Future income tax recovery	(15,710)	(7,595)	(10,815)	(9,131)
	(15,743)	(7,437)	(10,749)	(8,904)
NET EARNINGS (LOSS) AND COMPREHENSIVE INCOME (LOSS)	2,328	(22,012)	14,819	(27,103)
RETAINED EARNINGS, BEGINNING OF PERIOD	97,136	114,126	84,645	119,217
RETAINED EARNINGS, END OF PERIOD	99,464	92,114	99,464	92,114
NET EARNINGS (LOSS) AND COMPREHENSIVE INCOME (LOSS) PER SHARE (note 7)				
Basic	0.03	(0.29)	0.17	(0.36)
Diluted	0.03	(0.29)	0.17	(0.36)
<i>Weighted average Class A shares – basic</i>	85,143,751	76,040,581	85,121,469	75,638,439
<i>– diluted</i>	85,143,751	76,040,581	85,121,469	75,638,439

See accompanying notes

GALLEON ENERGY INC.
Consolidated Statements of Cash Flows

(\$000s) (unaudited)	Three months ended June 30		Six months ended June 30	
	2010	2009	2010	2009
Cash provided by (used in):				
OPERATING ACTIVITIES				
Net earnings (loss)	2,328	(22,012)	14,819	(27,103)
Items not requiring cash:				
Future income tax recovery	(15,710)	(7,595)	(10,815)	(9,131)
Depletion and depreciation	32,793	32,259	63,524	67,789
Accretion	723	664	1,437	1,323
Stock-based compensation	1,324	1,290	2,702	2,569
Unrealized (gain) loss on financial derivative	952	24,999	(17,577)	20,308
Goodwill allocated to disposed properties	4,736	-	4,736	-
Abandonment costs	(26)	(228)	(261)	(524)
Change in non-cash working capital	(3,185)	(1,992)	(1,630)	7,616
	23,935	27,385	56,935	62,847
FINANCING ACTIVITIES				
Issue of common shares	56	36,205	268	36,695
Repurchase of common shares	-	-	-	(32)
Share issue costs	-	(1,716)	-	(1,716)
Capital lease payment	(207)	(202)	(410)	(406)
Bank loan repayment	(117,832)	(27,790)	(105,524)	(13,186)
	(117,983)	6,497	(105,666)	21,355
INVESTING ACTIVITIES				
Disposal of (additions to) equipment inventory	1,070	1,896	(101)	4,420
Additions to oil and gas properties	(22,788)	(19,619)	(61,663)	(50,010)
Acquisition of oil and gas properties (note 3)	-	-	(16,966)	-
Disposition of oil and gas properties (note 3)	130,912	4,633	130,912	4,633
Change in non-cash working capital	(15,146)	(20,792)	(3,451)	(43,245)
	94,048	(33,882)	48,731	(84,202)
CHANGE IN CASH	-	-	-	-
CASH, BEGINNING AND END OF PERIOD	-	-	-	-
SUPPLEMENTARY INFORMATION				
Cash interest paid	3,266	1,293	6,740	3,091
Cash taxes paid	186	150	186	375

See accompanying notes

Notes to the Financial Statements
For the three and six month periods ended June 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 is in progress.

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 has completed analysis required to compile the opening IFRS balance sheet amounts.

Audit work on the opening balance sheet is expected to be completed during the fourth quarter of 2010. The Corporation's plans include preparation of the IFRS based comparative statements for each of the quarters ended in 2010 following completion of the opening balance sheet.

3. PROPERTY AND EQUIPMENT

	Cost	Accumulated depletion	Net book value
As at June 30, 2010	\$	\$	\$
Petroleum and natural gas properties & equipment	1,462,036	(540,857)	921,179
Equipment under capital lease	1,719	(509)	1,210
Office furniture and equipment	2,583	(1,328)	1,255
	1,466,338	(542,694)	923,644

	Cost	Accumulated depletion	Net book value
As at December 31, 2009	\$	\$	\$
Petroleum and natural gas properties & equipment	1,516,038	(477,553)	1,038,485
Equipment under capital lease	1,719	(443)	1,276
Office furniture and equipment	2,553	(1,174)	1,379
	1,520,310	(479,170)	1,041,140

During the three months ended June 30, 2010 the Corporation sold properties in the Puskwa area of Alberta for net cash consideration of \$130.9 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 six months ended June 30, 2010 the Corporation purchased non-producing assets in the Kakut area of Alberta for cash consideration of \$17.5 million. During the three month period ended June 30, 2009, certain minor properties were sold for net proceeds of \$4.6 million.

As at June 30, 2010, \$60.3 million (June 30, 2009- \$103.9 million) of undeveloped land and seismic have been excluded from and \$158.7 million (June 30, 2009 - \$164.1 million) in future development costs have been added into the full cost pool for depletion purposes. For the three and six months ended June 30, 2010, \$273,000 and \$545,000, respectively (June 30, 2009 – \$273,000 and \$545,000) of exploration salaries have been capitalized.

4. ASSET RETIREMENT OBLIGATION

The Corporation's asset retirement obligation results from its 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 \$124 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.

	Six months ended June 30, 2010 \$	Year ended December 31, 2009 \$
Balance, beginning of year	41,499	39,905
Accretion expense	1,437	2,651
Liabilities incurred	1,070	1,909
Disposition of liabilities	(1,839)	(1,685)
Settlement of liabilities	(261)	(1,281)
Change in estimates	(920)	-
Balance, end of period	40,986	41,499

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, excluding the capital leases. At June 30, 2010, an amount of \$111.7 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 June 30, 2010, the effective interest rates were 6.1% and 5.8%, respectively (June 30, 2009 - 2.6% and 2.5%).

As at June 30, 2010, the Corporation is in compliance with all covenants, obligations and conditions of its credit agreement.

6. CAPITAL LEASE OBLIGATIONS

The Corporation has an equipment lease financing arrangement with minimum lease payments of \$1.2 million remaining in 2010. The lease has an interest rate of 6.3 percent and the equipment purchase price at the end of the lease on September 1, 2010 is \$1.0 million. A general security agreement and a first charge against the equipment have been provided as collateral.

7. 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 \$
Balance at December 31, 2008	75,170,733	547,298
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
Balance at December 31, 2009	85,090,883	599,334
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
Balance at March 31, 2010	85,135,883	595,162
Issued for cash on exercise of stock options	12,000	56
Transfer from contributed surplus	-	21
Balance at June 30, 2010	85,147,883	595,239

- 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 June 30, 2010, \$12.2 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. No shares were purchased during the six months ended June 30, 2010.

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.

	Six months ended June 30, 2010	Year ended December 31, 2009
Contributed Surplus	\$	\$
Beginning of period	28,884	23,009
Stock based compensation expense	2,702	6,114
Transfer to share capital	(99)	(238)
Paid on surrender of share options	-	(1)
End of period	31,487	28,884

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 36-59%; and an average expected life of the options of 3 years.

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

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.

8. INCOME TAXES

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

	June 30, 2010	December 31, 2009
	\$	\$
Property and equipment	73,385	99,668
ACRI benefit	(1,302)	(1,260)
Share issue costs	(1,240)	(1,770)
Asset retirement obligation	(1,499)	(1,193)
Non-capital losses	(6,530)	(28,932)
Partnership income tax deferral	20,418	27,749
Capital leases	(295)	(402)
Financial derivative	2,088	(2,482)
Future income tax liability	85,025	91,378
Less current future income tax liability	1,216	2,884
Long term portion of future income tax liability	83,809	94,262

The income tax recovery recorded during the three months ended June 30, 2010 includes a \$12.7 million benefit relating to the disposition of properties.

9. COMMITMENTS

Office Lease Payments

At June 30, 2010 the Corporation is committed to \$0.6 million in future minimum payments under operating leases for office space in 2010.

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.

10. 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 June 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 June 30, 2010, approximately 44% 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 June 30, 2010 as the Corporation has assessed there are no impaired receivables.

Accounts Receivable	\$
Less than 90 days	30,469
Greater than 90 days	4,041
Total	34,510

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 June 30, 2010:

Natural Gas:

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

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

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 June 30, 2010 the fair value is estimated to be a net asset of \$8.0 million, composed of an \$8.3 million short term asset, a \$2.2 million long-term asset, and a \$2.5 million current 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.

11. 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 June 30 (\$000s)	Target Measure	2010 \$	2009 \$
Components of ratios			
Current assets (excluding fair value of financial derivative and future income taxes)		40,320	40,896
Current liabilities (including short term debt and excluding fair value of financial derivative and future income taxes)		156,164	272,986
Net debt		115,844	233,225
Total debt (bank loan and capital leases)		112,854	238,302
Shareholders' equity (share capital plus retained earnings)		694,703	675,060
Total capitalization (total debt plus shareholders' equity)		807,557	913,362
Funds from operations ¹ (six months ended June 30 annualized)		117,652	111,510
Net debt/funds from operations	< 1.5 times	1.0	2.1
Total debt/total debt plus shareholders' equity	< 0.4 times	0.1	0.3

1 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 in 2010 from 2009 resulted from a decrease in net debt and an increase in funds from operations.

12. 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 three months ended June 30, 2010.

13. SUBSEQUENT EVENT

Subsequent to June 30, 2010 the Corporation committed to future minimum lease payments under an operating lease for office space with future minimum lease payments as follows:

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