

GALLEON ENERGY INC.

Management's Discussion & Analysis

December 31, 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 year ended December 31, 2010, with comparisons to the year ended December 31, 2009. The MD&A has been prepared by management and should be read in conjunction with the audited financial statements for the year ended December 31, 2010, which are prepared in accordance with Canadian generally accepted accounting principles ("GAAP").

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, March 10, 2011.

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, anticipated timing of regulatory approvals, planned completion techniques in certain areas, 2011 capital expenditure budget and the anticipated method of funding thereof, method of funding of potential acquisitions, expected level of 2011 cash flows compared to 2010, 2011 operating costs and royalties, expected continued volatility in commodity prices and stock markets and plans and timing related to the adoption of International Financial Reporting Standards ("IFRS") and policy choices to be made under IFRS and certain anticipated effects of adoption of IFRS.

Projected level of 2011 cash flows may constitute future oriented financial information or a financial outlook under applicable securities laws, which was approved by management of the Corporation as at March 10, 2011. This is provided to provide readers with a comparison of expected 2011 cash flows compared to 2010 based on the various assumptions described. Readers are cautioned that the information may not be appropriate for other purposes.

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.

Annual Information

<i>(\$000s except per share amounts)</i>	2010	2009	2008
Revenues before royalties and financial derivatives	207,831	213,144	418,233
Funds from operations ¹	100,478	97,393	241,298
Per share – basic	1.19	1.22	3.39
Per share – diluted	1.19	1.22	3.35
Net earnings (loss)	(38,947)	(34,572)	79,264
Per share - basic	(0.46)	(0.43)	1.11
Per share – diluted	(0.46)	(0.43)	1.10
Capital expenditures – exploration & development	136,570	106,095	273,598
Acquisitions (dispositions) of oil and gas properties, net	(114,158)	(8,451)	17,541
Total assets	993,375	1,136,732	1,181,003
Net debt ^{1,2}	152,861	226,859	282,446
Total non-current financial liabilities	14,980	-	1,541
Shareholders' equity	669,709	712,863	689,524
Weighted average shares outstanding			
Basic	84,770,976	79,656,109	71,105,806
Diluted	84,770,976	79,656,109	72,128,065

¹ See "Non-GAAP Measurements"

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

The 2% decrease in revenues in 2010 compared to 2009 was primarily due to lower crude oil production volumes, partially offset by increased crude oil prices during the year. The 1,176 BOE per day reduction in production volumes reflects the sale of properties, primarily the Puskwa light oil assets sold in the second quarter of 2010, and a decrease in heavy oil volumes. Average production in 2010 was 14,800 BOE/d compared to 15,976 BOE/d in 2009. Excluding volumes from properties which were sold, average production for the year ended December 31, 2010 was 2% higher than the average production recorded in 2009. Crude oil prices, before transportation and financial derivative contracts, averaged \$70.71/Bbl in 2010, up 20% from \$59.01/Bbl in 2009.

Funds from operations increased by 3% in 2010 from 2009, due to lower operating costs and higher realized gains on financial derivative contracts. Operating expenses decreased by \$5.3 million or \$0.21/BOE from 2009, to \$9.52/BOE for the year ended December 31, 2010. The \$3.9 million increase in realized gains on financial derivatives in 2010 reflects higher gains on natural gas derivative contracts combined with lower losses on oil derivative contracts.

Net debt at December 31, 2010 was \$152.9 million. The \$74.0 million reduction from the \$226.9 million outstanding at the end of 2009 represents a decrease of 33%. Debt was reduced during 2010 with the application of proceeds received on the sale of the Puskwa assets during the second quarter of 2010.

The net loss in 2010 includes a \$30.2 million non-cash impairment of goodwill. There was no impairment to the carrying amount of the Corporation's petroleum and natural gas properties during 2010.

Results of Operations

Year ended December 31	2010		2009	
	5,401,855 BOE		5,831,086 BOE	
(\$000s)		\$/BOE		\$/BOE
Revenues	207,831	38.47	213,144	36.55
Realized gain on financial derivatives	10,552	1.95	6,651	1.14
Other income	-	-	752	0.13
Royalties	(44,060)	(8.15)	(55,032)	(9.44)
GCA ¹	12,670	2.35	22,320	3.83
Transportation costs	(8,806)	(1.63)	(8,165)	(1.40)
Operating costs	(51,405)	(9.52)	(56,714)	(9.73)
	126,782	23.47	122,956	21.08
General and administration	(14,773)	(2.73)	(15,911)	(2.73)
Restructuring costs	(1,242)	(0.23)	-	-
Interest costs	(10,086)	(1.87)	(9,226)	(1.58)
Capital and other taxes	(203)	(0.04)	(426)	(0.07)
Funds from operations²	100,478	18.60	97,393	16.70

¹ GCA means Gas Cost Allowance

² See "Non-GAAP Measurements"

Petroleum and Natural Gas Revenues

Year ended December 31	2010		2009	
		%		%
(\$000s)				
Light oil	78,943	38	87,854	41
Heavy oil	23,481	11	22,961	11
NGLs	9,379	5	8,731	4
Natural gas	95,615	46	93,261	44
Royalty income	413	-	337	-
Total	207,831	100	213,144	100

Revenues for the year ended December 31, 2010 decreased by 2% to \$207.8 million from \$213.4 million in the prior year. Gas revenues increased in 2010 due to increases in both production volumes and natural gas prices. The increase in oil prices during 2010 was more than offset by a decrease in production volumes, resulting primarily from the sale of properties, including the Puskwa light oil properties sold in the second quarter of 2010.

Production

Year ended December 31	2010		2009	
	BOE/d	%	BOE/d	%
Light oil (Bbls/d)	2,913	20	3,924	25
Heavy oil (Bbls/d)	1,065	7	1,229	8
NGLs (Bbls/d)	472	3	575	3
Natural gas (Mcf/d)	62,098	70	61,487	64
BOE/d (6:1)	14,800	100	15,976	100

Average production was 14,800 BOE/d during 2010, 7% lower than the average production of 15,976 during 2009. Daily production volumes varied by product as follows: light oil decreased by 26%; heavy oil decreased by 13%; natural gas liquids decreased by 18% and natural gas increased by 1%.

Commodity Pricing and Marketing

Petroleum products are sold to major Canadian marketers at either 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 December 31, 2010:

Natural Gas		
January 1, 2010 - December 31, 2011	5,000 GJ/d	CDN \$5.85/GJ
January 1, 2010 - December 31, 2011	5,000 GJ/d	CDN \$5.75/GJ
April 1, 2010 - March 31, 2011	5,000 GJ/d	CDN \$5.76/GJ
January 1, 2011 - December 31, 2011	20,000 GJ/d	CDN \$5.20/GJ
April 1, 2011 - December 31, 2011	5,000 GJ/d	CDN \$5.60/GJ
Crude Oil		
Fixed Price		
January 1, 2011 – December 31, 2011	500 Bbl/d	WTI CDN \$92.00/Bbl
January 1, 2011 – December 31, 2011	1,000 Bbl/d	WTI CDN \$84.15/Bbl
Costless Collars		
January 1, 2011 – December 31, 2011	1,000 Bbl/d	WTI CDN \$77.10-\$90.00/Bbl
Other		
January 1, 2012 – December 31, 2012	1,000 Bbl/d	WTI US \$85.00/Bbl Call
January 1, 2012 – December 31, 2012	527 Bbl/d	WTI US \$85.00/Bbl Call
January 1, 2012 – December 31, 2012	1,100 Bbl/d	WTI US\$ 85.00 Swaption
Interest Rate Swap		
Notional Amount CAD \$100 million	Term: January 20, 2009 – January 20, 2011	
Fixed rate 1.1% - Floating rate is reset against CAD--CDOR on each 3 month anniversary		

During the year, the Corporation realized gains of \$10.6 million on financial contracts, which included a loss of \$0.3 million on the interest rate swap. This compared to a \$6.7 million gain realized in 2009. Based on the mark to market value at December 31, 2010, an unrealized gain on financial contracts of \$9.0 million was recorded in 2010, compared to an unrealized loss of \$10.8 million in 2009. If the contracts were unwound at December 31, 2010, the Corporation would be obligated to pay a net amount of \$0.6 million.

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

Year ended December 31	2010	2009
Light oil (\$/Bbl)	74.50	61.42
Heavy oil (\$/Bbl)	60.41	51.29
NGLs (\$/Bbl)	54.44	41.60
Natural gas (\$/Mcf)	4.23	4.16

During 2010, as compared to 2009, the light oil price increased by 21%, the heavy oil price increased by 18%, the NGL price increased by 31%, and the natural gas price increased by 2%.

Crude Oil Prices

Year ended December 31	2010		2009	
	\$000s	\$/Bbl	\$000s	\$/Bbl
Crude oil	102,664	70.71	110,978	59.01
Realized financial contracts	(3,811)	(2.63)	(6,750)	(3.59)
Transportation	(1,831)	(1.26)	(1,954)	(1.04)
Net crude oil	97,022	66.82	102,274	54.38

Natural Gas Prices

Year ended December 31	2010		2009	
	\$000s	\$/Mcf	\$000s	\$/Mcf
Natural gas	95,788	4.23	93,435	4.16
Realized financial contracts	14,646	0.65	13,814	0.62
Transportation	(6,967)	(0.31)	(6,132)	(0.27)
Net natural gas	103,467	4.57	101,117	4.51

NGL Prices

Year ended December 31	2010		2009	
	\$000s	\$/Bbl	\$000s	\$/Bbl
NGL	9,379	54.44	8,731	41.60
Transportation	(8)	(0.05)	(79)	(0.38)
Net NGL	9,371	54.39	8,652	41.22

Performance by Property

Year ended December 31

	2010				2009			
	Production		Operating netbacks/ BOE ¹	Funds from operations ²	Production		Operating netbacks/ BOE ¹	Funds from operations ²
	BOE/d	%	\$	%	BOE/d	%	\$	%
Eastern Montney	5,452	37	20.42	39	4,970	31	15.78	31
Kakut	4,194	28	18.72	28	3,412	21	16.65	22
North Peace River Arch	4,423	30	15.26	24	5,372	34	11.28	24
Sold properties	731	5	34.77	9	2,222	14	27.11	23
	14,800	100	19.11	100	15,976	100	16.03	100

¹ Operating netbacks/BOE exclude GCA, other income and hedging gains or losses, and are calculated by subtracting royalties and operating costs from revenues and dividing the result by the average production for the period

² See "Non-GAAP Measurements"

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

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

Eastern Montney production averaged 5,452 BOE/d (74% natural gas and 26% oil and NGLs) during 2010, a 10% increase from the average production during 2009. The Eastern Montney natural gas project continues to represent a significant resource to Galleon and is the Corporation's largest producing area. Low operating costs for the area enabled it to contribute 39% to total funds from operating activities in 2010 based on 37% of production volumes. The economics of this project are strong due to the low operating costs and associated oil and NGL's that are produced with the gas.

The Eastern Montney project was initially developed using vertical wells. However, as technology evolved to allow effective stimulation of horizontal wellbores, Galleon implemented horizontal development in 2008. As of the end of 2010, Galleon has drilled a total of 61 horizontal wells and 83 vertical wells in the project area. The project area encompasses a large fairway that is 30 miles long by 10 miles wide that has been mapped and tested. Galleon's approach to this project during 2010 was to pursue a level of drilling activity that would utilize the capacity available in our existing gas plant. This will be the approach until gas prices improve, at which time the project will be considered for expansion. During 2010 Galleon drilled a total of 22 wells.

During Q4 Galleon has also encountered a Montney oil leg that is being further developed in 2011. In Q4 2010, a total of 4 wells were drilled into this oil leg with an additional three follow up locations planned for Q1 2011. The one month gross production average for each of these four wells is 107 BOE/d (76% working interest). Galleon will continue to delineate and exploit this oil accumulation throughout 2011.

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

The Kakut property continues to be a significant growth area for Galleon. Production for 2010 averaged 4,194 BOE/d (75% natural gas and 25% oil and NGLs), representing an increase of 23% from 2009.

The Kakut property contributed 28% of total funds from operating activities based on 28% of production volumes in 2010.

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

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

In 2010, Galleon drilled 19 Doig horizontal wells at Kakut. The Company plans to continue drilling on this project at a measured pace and to closely monitor results. The evolution of a cost effective drilling and completion technique will help achieve the optimal depletion strategy. In order to model these early-stage and long-term well-performance expectations there will be a focus in 2011 on developing a reliable simulation, based upon production and pressure, as well as incorporating petrophysical parameters gathered from open-hole logs and core.

In Q3 2010, two wells, 04-28-74-03W6 and 16-06-75-03W6 (both 100% working interest) located in the Doig B pool, which were producing a total of approximately 900 BOE/d (83% natural gas and 17% oil and NGLs) were shut in due to high gas-oil ratios (GOR's), after their four month new oil well production period (NOWPP) came to an end. Galleon received approval from the ERCB for Temporary Net Gas-Oil Ratio Penalty relief in the Kakut Doig B pool for the go forward period of January 1, 2011 to December 31, 2011. This 12 month timeframe will allow Galleon to observe and design an optimal depletion strategy for the pool.

During 2010, Galleon received approval for the remaining Kakut Doig holding applications outstanding. A total of 11 sections are approved for 4 horizontal wells per section. In addition, holdings for 9 more sections have been applied for based on 4 horizontal wells per section with an anticipated approval in late Q2 2011.

Edam continues to deliver consistent production with the implementation of a cost effective chemical program which keeps sand/water/oil in suspension long enough to mitigate production problems. The program is ongoing in our current wells and selected reactivations.

In Sawn Lake during the first quarter of 2011, 2 horizontal wells will be drilled with a partner. Galleon's working interest in these wells is 25%. Several companies operating in the same area have seen prolific results using multi-stages with acid, which is the completion technique that will be used in the Galleon wells.

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

Production in the NPRA business unit averaged 4,423 BOE/d in 2010 (70% natural gas and 30% oil and NGLs), a decrease of 18% from 2009. In 2010, NPRA contributed 24% of the funds from operations and 30% of production volumes.

In this business unit, Galleon has targeted two emerging Triassic oil plays. The Company has assembled an extensive land position over the plays. One vertical well in the first Triassic oil project was recompleted in Q4 2010 with encouraging results. This recompletion, along with vertical well control and seismic, provides support for an emerging Triassic oil play. This play has considerable areal extent and thick hydrocarbon charge. Galleon will focus on horizontal drilling technology to develop these opportunities.

The Company has also identified natural gas opportunities in the area. Large oil-in-place assets at Alexis/St. Anne will also continue to be exploited and optimized.

In 2010, Galleon drilled 6 (5.0 net) vertical wells targeting primarily gas, and 3 (2.7 net) horizontal wells targeting primarily oil in the NPRA area.

Royalties

Year ended December 31	2010	2009
(\$000s, except as indicated)		
Crown	35,877	48,504
Freehold	4,063	2,299
GORR and other	4,120	4,229
Gross royalties	44,060	55,032
GCA	(12,670)	(22,320)
Net royalties	31,390	32,712
% of revenue	21.2	25.8
% of revenue net of GCA	15.1	15.3

Gross royalties were 21.2% of revenues for the year ended December 31, 2010, compared to 25.8% in 2009. By product during the year ended December 31, 2010, gross royalties were 25.0% for light oil, 17.2% for natural gas, 22.6% for heavy oil, and 26.8% for liquids. For the year ended December 31, 2009, gross royalties were 27.7% for light oil, 23.9% for natural gas, 21.7% for heavy oil, and 35.5% for liquids.

Net royalties were 15.1% for 2010 compared to 15.3% in 2009.

The gross royalty rate for natural gas decreased in 2010 as compared to 2009 due primarily to royalty rate reductions applicable to production from new wells. Freehold royalties increased by \$1.8 million in 2010 from 2009 due to freehold production from new wells and freehold production tax related to a prior period.

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 December 31, 2010 the Corporation had recorded drilling credits of \$20.9 million as a reduction of property and equipment, an increase of \$9.4 million from December 31, 2009. Of the total \$20.9 million in drilling credits recorded, \$18.3 million had been received at December 31, 2010.

Operating Costs

Year ended December 31	2010			2009		
	Production	Operating Costs		Production	Operating Costs	
	%	%	\$/BOE	%	%	\$/BOE
Eastern Montney	37	34	8.90	31	31	9.77
Kakut	28	25	8.29	21	18	7.96
North Peace River Arch	30	38	11.99	34	41	11.92
Sold properties	5	3	6.19	14	10	7.05
	100	100	9.52	100	100	9.73

Operating costs decreased by \$0.21/BOE, or 2%, to \$9.52/BOE in 2010 from \$9.73/BOE in 2009.

In the Eastern Montney natural gas project, operating costs were \$8.90/BOE in 2010 compared to \$9.77/BOE in 2009. The 9% decrease in operating costs per unit was a function of increased production volumes in the area.

Operating costs at Kakut were \$8.29/BOE in 2010, an increase of 4% from \$7.96/BOE in the prior year. Higher chemical costs were partially offset by increased facility income and reduced water trucking expenses.

The \$11.99/BOE operating cost at NPRA during 2010 was comparable to the 2009 operating cost of \$11.92/BOE.

General and Administration Expenses

Year ended December 31	2010		2009	
(\$000s)	\$/BOE		\$/BOE	
Gross	20,016	3.71	20,616	3.54
Capitalized overhead	(3,411)	(0.64)	(3,046)	(0.52)
Overhead recoveries	(1,832)	(0.34)	(1,659)	(0.29)
	14,773	2.73	15,911	2.73

Gross general and administrative expenses (“G&A”) decreased by \$0.6 million in 2010. The decrease reflects lower engineering and office costs, which were partially offset by higher employee expenses. Capitalized overhead was \$0.12 per BOE higher in 2010, reflecting increased capital spending during 2010 compared to 2009.

For the year ended December 31, 2010 G&A expenses by category were: salary and employee – 59%, office – 18%, consulting – 6%, computer – 6%, shareholder costs – 1%, audit, engineering and legal – 7%, 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 cash consideration, net of adjustments, of \$131.4 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 during the year ended December 31, 2010.

Interest

Interest expense was \$10.1 million in 2010, \$0.9 million higher than the \$9.2 million expense incurred in 2009. A lower average debt balance outstanding during 2010, resulting from the application of proceeds received on the sale of the Puskwa assets, was offset by an increase in the effective interest rate. The effective interest rate during 2010 was 5.8% (2009 – 3.8%).

As at December 31, 2010 an amount of \$135.7 million was drawn against the Corporation’s credit facilities, compared to \$217.2 million at December 31, 2009.

Stock-Based Compensation

Stock-based compensation was a non-cash expense of \$4.1 million in 2010 compared to \$6.1 million in 2009, a \$2.0 million decrease. Stock-based compensation expense in 2010 included forfeitures of unvested options which resulted in previously recorded stock based compensation expense being reversed.

During the year, 2.6 million stock options were granted at an average exercise price of \$4.30 per share and had fair values between \$1.53 and \$2.40 per option.

At December 31, 2010 there were 7,150,000 stock options were outstanding at an average exercise price of \$5.44 per share.

Depletion, Depreciation and Accretion

Depletion and depreciation (“D&D”) charges were \$128.3 million or \$23.75/BOE for the year ended December 31, 2010, compared to \$127.9 million or \$21.94/BOE in the prior year. Reserves at December 31, 2010 were estimated by an independent third party qualified reserves evaluator.

Capital expenditures of \$51.4 million (December 31, 2009 - \$86.6 million) related to undeveloped land and seismic have been excluded from the depletion and depreciation calculation, and \$176.3 million (December 31, 2009 - \$199.7 million) of future development costs have been added into the cost base for depletion purposes.

Accretion expense on the Corporation’s asset retirement obligation of \$2.9 million for the year increased from an expense of \$2.7 million in the prior year.

Impairment of Goodwill

The Corporation reviewed the valuation of goodwill as of December 31, 2010 and determined that the fair value of the reporting unit had declined below its carrying value. Based upon this review, an impairment of goodwill of \$30.2 million (December 31, 2009 - \$nil) was recorded as a non-cash charge to earnings as of December 31, 2010. There was no impairment to the carrying amount of the Corporation’s petroleum and natural gas assets as at December 31, 2010.

Capital and Future Taxes

The current tax provision of \$0.2 million (2009 - \$0.4 million) was related to Saskatchewan capital and resource tax and was based upon revenues earned in Saskatchewan. A future income tax recovery of \$21.7 million was recorded in 2010 on a loss before tax of \$60.5 million. An income tax recovery of \$15.5 million was recorded in 2009 on a loss before tax of \$49.7 million. Galleon has estimated tax deductions of approximately \$590.0 million available at December 31, 2010.

Capital Expenditures

	(\$000s)
Property & equipment balance at December 31, 2009	1,041,140
Additions to property and equipment	136,570
Disposition of property and equipment	(131,949)
Acquisitions of property and equipment	17,791
Asset retirement obligation additions	1,065
Asset retirement obligation dispositions	(1,839)
Depletion and depreciation	(128,284)
Property & equipment at December 31, 2010	934,494

Year ended December 31	2010		2009	
(\$000s)		%		%
Land	6,807	5	5,080	5
Geological and geophysical	2,354	2	2,688	3
Drilling and completion	104,663	77	60,067	56
Plant and facilities	22,634	16	38,199	36
Other assets	112	-	61	-
Exploration and development expenditures	136,570	100	106,095	100

Exploration and development expenditures during 2010 were \$136.6 million. During the year the Corporation drilled 69 (64.9 net) wells, resulting in 30 (28.9 net) gas wells, 36 (33.0 net) oil wells, and 3 (3.0 net) dry & abandoned wells, for a success rate of 95%.

Facility expenditures of \$22.6 million were incurred in 2010. Land and seismic expenditures totaled \$6.8 million and \$2.4 million, respectively, in 2010. In November 2010, management established an exploration and development capital budget of approximately \$131.0 million for 2011, depending upon levels of cash flow. The Corporation expects to fund substantially all of the 2011 capital program with cash flow from operations and not with incremental working capital.

Liquidity and Capital Resources

December 31	2010	2009
(\$000s)		
Bank debt	135,682	217,243
Working capital deficiency ¹	17,179	9,616
Total net debt	152,861	226,859

¹ Excludes future income taxes and fair value of financial derivatives

The final payment required under the equipment capital lease was made during the year ended December 31, 2010.

Funding of Capital Program

Year ended December 31	2010	2009
(\$000s)		
Issuance (repurchase) of shares, net of costs	(3,817)	51,086
Funds from operations	100,478	97,393
Change in bank debt	(81,561)	(31,772)
Change in capital leases	(1,545)	(2,106)
Acquisition of properties	(17,791)	(350)
Disposition of properties	131,949	8,801
Change in inventory	240	6,033
Change in working capital and other	8,617	(22,990)
Exploration and development expenditures	136,570	106,095

The Corporation has \$250 million in credit facilities available consisting of a \$225 million extendible 364 day revolving term facility and a \$25 million non-revolving facility. The \$25 million facility is available subject to mutual approval of the banking syndicate and the Corporation, including repayment terms.

Collateral for the facilities consists of a demand debenture for \$500 million collateralized by a first floating charge over all of the property and equipment of the Corporation. At December 31, 2010, an amount of \$135.7 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 year ended December 31, 2010, the effective interest rate was 5.8% (December 31, 2009 - 3.8%).

An annual review is scheduled to occur on or before May 28, 2011. The level of the borrowing base will be determined by the bank syndicate based upon their review of, among other things, the Corporation's reserves and the value thereof, utilizing commodity prices determined by the bank syndicate which will be different than that utilized by the Corporation's independent reserve evaluator.

The Corporation entered into a fixed rate contract for a two year period commencing on January 20, 2009 and ending on January 20, 2011. The Corporation paid a fixed rate of 1.1% on \$100 million and received a three month CDOR floating rate from the counterparty to the contract.

Sensitivity Analysis

The following table shows sensitivities to funds from operations as a result of fluctuations in product prices, production volumes and other market factors. The table is based on the base case budgeted 2011 prices and forecast 2011 average production volumes.

Change to annual funds from operations	Change	\$000s	\$/share²
Price per barrel of oil (US\$ WTI) ¹	\$1.00	800	0.01
Price per mcf of natural gas (C\$ AECO) ¹	\$0.25	1,400	0.02
Oil production volumes	100 Bbl/d	2,000	0.02
Gas production volumes	1 Mmcf/d	600	0.01
Exchange rate (US/Canadian)	\$0.01	700	0.01
Interest rate on debt (\$125 million)	1%	1,200	0.01

¹ After adjustment for estimated royalties

² Based on basic shares outstanding at December 31, 2010

Commitments

Office Lease Payments

At December 31, 2010 the Corporation is committed to future minimum payments under operating leases for office space as follows:

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

Fracturing and Coiled Tubing Services

The Corporation has entered into a contract for fracturing and coiled tubing services under which the Corporation has committed to a minimum payment of \$6.0 million in 2011 at competitive rates.

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.

Financial Instruments

Refer to the “Commodity Pricing and Marketing” section.

Fourth Quarter Results

Three months ended December 31	2010		2009	
	1,247,109 BOE		1,351,338 BOE	
(\$000s)	\$	\$/BOE	\$	\$/BOE
Revenues	45,995	36.88	56,287	41.65
Realized gain (loss) on financial derivatives	1,368	1.10	(2,159)	(1.60)
Royalties	(8,555)	(6.86)	(14,406)	(10.66)
GCA ¹	3,042	2.44	5,069	3.75
Transportation costs	(2,085)	(1.67)	(1,797)	(1.33)
Operating costs	(12,612)	(10.11)	(12,582)	(9.31)
	27,153	21.78	30,412	22.50
General and administration	(4,212)	(3.38)	(4,430)	(3.28)
Interest costs	(1,645)	(1.32)	(3,063)	(2.27)
Capital and other taxes	(69)	(0.06)	(99)	(0.07)
Funds from operations²	21,227	17.02	22,820	16.88

¹ GCA means Gas Cost Allowance

² See “Non-GAAP Measurements”

Funds from operations decreased by \$1.6 million or 7% during Q4 2010 compared to Q4 2009. Lower crude oil production volumes and lower natural gas prices offset the benefits of lower royalty rates, reduced interest expense and higher realized gains on financial derivative contracts in Q4 2010.

For the three months ended December 31, 2010 production volumes decreased by 8% to 13,556 BOE/d from 14,688 BOE/d in the same period of the prior year. Average production volumes for Q4 2010 were as follows: light oil – 2,600 Bbl/d; heavy oil – 985 Bbl/d; natural gas – 57,459 Mcf/d; and NGLs – 394 Bbl/d.

Excluding volumes from properties which were sold, production increased by 3% to 13,556 BOE/d in Q4 2010, compared to 13,181 BOE/d in Q4 2009.

Natural gas prices, before financial derivative contracts and transportation, averaged \$3.81/Mcf in Q4 2010, 17% lower than the \$4.60/Mcf received in Q4 2009. Excluding transportation and financial derivative contracts, crude oil prices averaged \$72.01/Bbl in Q4 2010, 3% higher than the \$70.06/Bbl realized in Q4 2009. The average light oil price received in Q4 2010 rose 5% to \$76.44/Bbl from \$72.88

/Bbl in the fourth quarter of the prior year. The average heavy oil price in Q4 2010 of \$60.32/Bbl was 3% lower than the \$62.23/Bbl received in Q4 2009.

The gross royalty rate for light oil was 21.6% during the fourth quarter of 2010, compared to an average rate of 29.2% during Q4 2009. The decrease in Q4 2010 reflects the sale of higher royalty rate properties and royalty rate reductions applicable to production from new wells.

Operating costs were consistent at \$12.6 million during the fourth quarters of both 2010 and 2009. On a per unit basis, operating costs were \$10.11/BOE in the fourth quarter of 2010, a 9% increase from \$9.31/BOE during the same period of the prior year. The increase in operating costs per BOE was due primarily to increased chemical costs at Kakut, as well as higher workover, propane and fuel costs on a larger number of producing Doig oil wells.

Net G&A expenses of \$4.2 million in Q4 2010 were 5% lower than Q4 2009. In Q4 2010 net G&A expenses were \$3.38/BOE, an increase of 3% compared to \$3.28/BOE in Q4 2009.

Interest expense decreased by \$1.4 million in Q4 2010 compared to Q4 2009. A lower average debt balance was outstanding during Q4 2010 as a result of the application of proceeds received on the sale of the Puskwa assets in the second quarter of 2010.

The \$3.5 million increase in realized financial derivatives in Q4 2010 reflects higher gains on natural gas derivative contracts, combined with lower losses on crude oil derivative contracts.

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 continued in 2009. 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. Although economic conditions improved towards the latter portion of 2009 and in 2010, as anticipated, the recovery from the recession has been slow in various jurisdictions including in Europe and the United States that has been impacted by various ongoing factors including sovereign debt levels and high levels of unemployment which continue to impact commodity prices and result in high volatility in the stock market.

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. 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, 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.

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, and the impact analysis and evaluation phases. Major differences between Canadian GAAP and IFRS have been identified and quantified. The implementation and review phase is nearing completion.

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

The opening balance sheet as at January 1, 2010 is substantially determined. The Corporation is preparing IFRS based comparative statements for each of the quarters ended in 2010. Certain of the impacts of adoption of IFRS have been prepared by management and certain of them are described herein. Readers are cautioned, however, that such amounts have not been audited by the Corporation's auditors, nor approved by the Audit Committee or Board of Directors of the Corporation and may still be subject to change.

IFRS 1 election for full cost oil and gas entities

The Corporation expects to elect under IFRS 1 8(D) to measure the Canadian full cost pool upon transition to IFRS (the "full cost exemption"). Exploration and evaluation assets are expected to be

recorded at the amount determined under Canadian GAAP, and the remaining full cost pool is expected to be allocated to production and development assets pro-rata using proven and probable reserve values. There are no exploration and evaluation assets on January 1, 2010 expected.

As a part of the full cost exemption, assets are required to be assessed for impairment upon transition. Under IFRS, the impairment test compares the carrying value of an asset to the greater of its fair value less costs to sell or its value in use. IFRS impairment calculations are done at an asset or cash-generating unit (CGU) level, compared to being calculated at the country cost centre under Canadian GAAP. CGUs are identified on the basis of cash inflows being independent from other assets or groups of assets. The impairment tests on transition are expected to result in a \$165.3 million (\$122.3 million net of deferred tax) impairment of development and production assets.

Goodwill

Under IFRS, goodwill has been allocated to CGU's and tested for impairment at the operating segment level, compared to an impairment calculation at the reporting unit under Canadian GAAP. This change is expected to result in a \$9.6 million write-down of goodwill upon transition to IFRS.

Decommissioning liabilities

Under Canadian GAAP decommissioning liabilities were discounted at an average historical credit adjusted risk free rate of 7.4%. Under IFRS the estimated cash flow to abandon and remediate the wells and facilities is expected to be discounted at the January 1, 2010 credit adjusted risk free rate of 8%. As a result of the election for full cost oil and gas entities described above, this is expected to result in a \$3.3 million decrease in the decommissioning liability, with a corresponding increase in retained earnings (\$2.4 million net of deferred tax) on transition.

Flow-through shares

The Corporation has financed a portion of its exploration and development activities through the issuance of flow-through shares. Under the terms of the flow-through share agreements, the tax attributes of the related expenditures are renounced to subscribers. Under Canadian GAAP, to recognize the foregone tax benefits to the Corporation, the carrying value of the shares issued is reduced by the tax effect of the tax benefits renounced to subscribers when the renouncements are filed.

Under IFRS, share capital is recorded at the fair value of the shares issued, excluding any premium received for the tax benefits to be renounced. The difference between the premium received and the liability for the tax benefits renounced is recorded as tax expense on the effective date of the renouncement. Upon transition to IFRS, this is expected to result in a decrease to share capital of \$3.8 million, an increase to deferred income taxes of \$4.5 million, and a decrease to retained earnings of \$0.7 million. The \$4.5 million future tax liability and corresponding reduction to share capital booked under Canadian GAAP in 2010 when the flow-through renouncements were filed is expected to be reversed under IFRS.

Share-based compensation

Under Canadian GAAP, the Corporation recognized an expense related to share-based compensation on a straight-line basis over the vesting period, and the expense did not incorporate an estimated forfeiture rate. Under IFRS, the Corporation is required to estimate a forfeiture rate and to recognize share-based compensation over the individual vesting periods for graded vesting awards. Upon transition to IFRS, this is expected to result in a \$1.3 million increase to contributed surplus with a corresponding decrease in retained earnings.

Development and production assets

Upon transition to IFRS, the Corporation expects to adopt a policy of depleting oil and natural gas interests on a unit of production basis using estimated proven plus probable reserves. The depletion policy under Canadian GAAP was based on units of production using estimated proven reserves. In addition, depletion was calculated for the Canadian cost centre under Canadian GAAP. IFRS requires items of property and equipment with significant costs to be depleted and depreciated separately.

There was no impact of this difference on adoption of IFRS at January 1, 2010 as a result of the IFRS 1 election for full cost oil and gas entities as discussed above.

Controls and Procedures

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.

Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's disclosure controls and procedures at the financial year end of the Corporation and have concluded that the Corporation's disclosure controls and procedures are effective at the financial year end of the Corporation for the foregoing purposes.

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 Canadian GAAP.

Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's internal controls over financial reporting at the financial year end of the Corporation and concluded that the Corporation's internal controls over financial reporting is effective, at the financial year end of the Corporation, for the foregoing purpose.

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 December 31:

	2010	2009
Class A shares outstanding		
Basic	83,980,083	85,090,883
Diluted ¹	91,130,083	91,824,717

¹ Includes 7,150,000 options at December 31, 2010 (December 31, 2009 – 6,733,834)

At December 31, 2010, the market value of Galleon's Class A shares was \$345.2 million based on the December 31, 2010 closing price of \$4.11 per Class A share. As of March 10, 2011, the number of Class A shares and options outstanding are 83,980,083 and 6,721,333 respectively.

On November 29, 2010, the Corporation received regulatory approval from the Toronto Stock Exchange for a Normal Course Issuer Bid ("Bid") to purchase in the open market for cancellation up to a maximum of 2,000,000 Class A shares of the Corporation. The Bid was effective December 1, 2010 and will terminate on November 30, 2011, or such earlier time as the Bid is completed or terminated at the option of the Corporation. Copies of the Notice are available to shareholders of Galleon from Galleon upon request and with charge.

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.

2011 Outlook

The 2011 capital expenditure budget of \$131 million is expected to be allocated 80% towards low risk development locations in the Eastern Montney natural gas, Doig light oil and North Peace River arch producing areas. Approximately 70% of the capital program is directed towards oil projects. Funding of the 2011 capital program is expected to be largely financed from internal cash flow. Additionally, acquisitions of both oil and gas properties are targeted. These acquisitions are expected to be financed by bank debt and the issuance of equity.

In July, 2010, the Corporation was restructured into three business units: Eastern Montney, Kakut and North Peace River Arch ("NPRA"). In 2011, approximately 31% of investment capital will be allocated to the Eastern Montney business unit, 45% to the Kakut business unit and 24% to the NPRA business unit.

In 2011, the Corporation will continue to farm 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 the lands while retaining a significant portion of the net resource. A number of opportunities have been identified on Galleon's land base of approximately 775,000 net acres.

Projected 2011 cash flows are approximately 20% higher than 2010 cash flows. Operating costs in 2011 are expected to average \$10.00/BOE and royalties, net of gas cost allowance, are budgeted to be less than 15% of revenues.

Galleon has used average commodity price assumptions of \$85/Bbl USD WTI for oil and \$3.70/GJ CDN for natural gas in the 2011 corporate budget. A foreign exchange rate of \$0.97 has been used. For 2011, the Corporation has commodity hedge contracts in place for 33.3 Mmcf/d of natural gas with an average fixed price of \$5.71/Mcf and 2,500 Bbl/d of crude oil with an average price of \$88.06/Bbl WTI Cdn.

Quarterly Highlights

	2010				2009			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production								
Light oil (Bbl/d)	2,600	2,517	3,295	3,249	3,364	3,872	4,024	4,447
Heavy oil (Bbl/d)	985	1,009	1,108	1,161	1,210	1,281	1,198	1,227
Natural Gas (Mcf/d)	57,459	59,186	67,689	64,165	57,752	57,012	61,733	69,632
Liquids (Bbl/d)	394	433	537	527	489	561	565	687
BOE/d	13,556	13,823	16,222	15,631	14,688	15,216	16,076	17,965
Total BOE produced	1,247,108	1,271,739	1,476,256	1,406,752	1,351,338	1,399,847	1,462,922	1,616,979
Daily BOE of production per million Class A shares – basic	161	163	191	184	174	184	211	239
Prices (prior to realized gains or losses on financial contracts and prior to transportation)								
Light oil (\$/Bbl)	76.44	71.26	72.53	77.47	72.88	67.12	61.39	47.53
Heavy oil (\$/Bbl)	60.32	58.13	57.76	64.91	62.23	57.27	51.54	33.65
Crude oil (\$/Bbl)	72.01	67.50	68.82	74.17	70.06	64.67	59.13	44.53
Natural Gas (\$/Mcf)	3.81	3.75	4.07	5.22	4.60	3.16	3.61	5.13
NGLs (\$/Bbl)	58.06	49.48	53.41	56.80	52.06	43.87	39.23	34.07
Per BOE (\$)								
Revenues	36.88	34.82	37.44	44.28	41.65	35.36	34.43	35.24
Royalties, net of GCA	(4.42)	(4.16)	(6.71)	(7.59)	(6.91)	(7.10)	(2.11)	(6.40)
Transportation costs	(1.67)	(1.66)	(1.64)	(1.56)	(1.33)	(1.41)	(1.41)	(1.45)
Operating costs	(10.11)	(10.20)	(9.03)	(8.88)	(9.31)	(9.32)	(9.43)	(10.70)
Net	20.68	18.80	20.06	26.25	24.10	17.53	21.48	16.69
Other revenue	-	-	-	-	-	-	0.05	0.42
G&A	(3.38)	(3.09)	(2.07)	(2.54)	(3.28)	(2.47)	(2.62)	(2.60)
Restructuring costs	-	(0.05)	(0.81)	-	-	-	-	-
Interest	(1.32)	(1.45)	(2.42)	(2.14)	(2.27)	(2.05)	(1.16)	(0.98)
Capital and other taxes	(0.06)	(0.05)	0.02	(0.07)	(0.07)	(0.07)	(0.11)	(0.04)
Realized gain (loss) on financial derivatives	1.10	1.90	3.61	1.02	(1.60)	0.50	2.58	2.68
Funds from operations¹	17.02	16.06	18.39	22.52	16.88	13.44	20.22	16.17

¹See "Non-GAAP Measurements"

Quarterly Highlights
(unaudited)

2010

	Q4	Q3	Q2	Q1
Financial (\$000s)				
Revenues	45,995	44,279	55,273	62,284
Operating costs	(12,612)	(12,978)	(13,328)	(12,487)
General & administrative expenses	(4,212)	(3,930)	(3,063)	(3,568)
Restructuring costs	-	(59)	(1,183)	-
Interest expense	(1,645)	(1,849)	(3,578)	(3,014)
Impairment of goodwill	30,155	-	-	-
Funds from operations¹	21,227	20,425	27,146	31,680
Per share, basic ¹	0.25	0.24	0.32	0.37
Per share, diluted ¹	0.25	0.24	0.32	0.37
Earnings (loss)	(48,145)	(5,621)	2,328	12,491
Per share, basic	(0.57)	(0.07)	0.03	0.15
Per share, diluted	(0.57)	(0.07)	0.03	0.15
Total assets	993,375	1,026,875	1,010,855	1,175,832
Weighted average outstanding Class A shares-basic	83,983,158	84,869,236	85,143,751	85,098,939
Weighted average outstanding Class A shares-diluted	83,983,158	84,869,236	85,143,751	85,098,939

Quarterly Highlights
(unaudited)

2009

	Q4	Q3	Q2	Q1
Financial (\$000s)				
Revenues	56,287	49,497	50,373	56,987
Operating costs	(12,582)	(13,045)	(13,790)	(17,297)
General & administrative expenses	(4,430)	(3,453)	(3,827)	(4,201)
Restructuring costs	-	-	-	-
Interest expense	(3,063)	(2,876)	(1,702)	(1,585)
Impairment of goodwill	-	-	-	-
Funds from operations¹	22,820	18,818	29,605	26,150
Per share, basic ¹	0.27	0.23	0.39	0.35
Per share, diluted ¹	0.27	0.23	0.39	0.35
Earnings	(5,654)	(1,815)	(22,012)	(5,091)
Per share, basic	(0.07)	(0.02)	(0.29)	(0.07)
Per share, diluted	(0.07)	(0.02)	(0.29)	(0.07)
Total assets	1,136,732	1,127,665	1,141,506	1,158,329
Weighted average outstanding Class A shares-basic	84,325,666	82,890,883	76,040,581	75,231,828
Weighted average outstanding Class A shares-diluted	84,325,666	82,890,883	76,040,581	75,231,828

¹See "Non-GAAP Measurements".