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Suite 400, 250 - 2 St. S.W.
Calgary, Alberta T2P 0C1
Canada

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082-35178

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GALLEON ENERGY INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2007

March 27, 2008

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ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	MMcf	million cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	MMcf/d	million cubic feet per day
Mstb	1,000 stock tank barrels	MMbtu	million British Thermal Units
Bbls/d	barrels per day	Bcf	billion cubic feet
BOPD	barrels of oil per day	GJ	gigajoule
NGLs	natural gas liquids	MM	Million
STB	standard tank barrels		

Other

AECO	A natural gas storage facility located at Suffield, Alberta.
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale.
ARTC	Alberta Royalty Tax Credit
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
BOE/d	barrel of oil equivalent per day
m^3	cubic metres
MBOE	1,000 barrels of oil equivalent
$000s	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Where any disclosure of reserves data is made in this annual information form (or the Appendices hereto) that does not reflect all reserves of Galleon, the reader should note that the estimates of reserves and future net revenue for individual properties or groups of properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

CONVERSIONS

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres (Alberta)	Hectares	0.400
Hectares (Alberta)	Acres	2.500
Acres (British Columbia)	Hectares	0.405
Hectares (British Columbia)	Acres	2.471

CERTAIN DEFINITIONS

In this Annual Information Form, the following words and phrases have the following meanings, unless the context otherwise requires:

"ABCA" means *Business Corporations Act* (Alberta);

"COGE Handbook" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"Class A Shares" means the Class A Shares in the capital of the Corporation;

"Class B Shares" means the Class B Shares in the capital of the Corporation;

"Corporation" or **"Galleon"** means Galleon Energy Inc.;

"DeGolyer" means DeGolyer and MacNaughton Canada Limited;

"DeGolyer Report" means the report of DeGolyer dated March 12, 2008 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2007;

"Development costs" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building, and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

"EUB" means the Alberta Energy and Utilities Board

"ExAlta" means ExAlta Energy Inc.;

"ExAlta BAR" means the business acquisition of the Corporation dated March 27, 2008 in respect of the acquisition of ExAlta;

"Exploration costs" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

"**Gross**" means:

(a) in relation to the Corporation's interest in production and reserves, its "company gross reserves", which are the Corporation's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;

(b) in relation to wells, the total number of wells in which the Corporation has an interest; and

(c) in relation to properties, the total area of properties in which the Corporation has an interest.

"**Net**" means:

(a) in relation to the Corporation's interest in production and reserves, the Corporation's working interest (operating and non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interests in production or reserves.

(b) in relation to wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and

(c) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

"**NI 51-101**" means National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities;

"**NRF**" means the New Royalty Framework announced by the Alberta government on October 25, 2007;

"**TSX**" means the Toronto Stock Exchange.

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2007.

All dollar amounts herein are in Canadian dollars, unless otherwise stated.

FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, financial and business prospects and financial outlook, reserve and production estimates, drilling plans, activities to be undertaken in various areas, timing of drilling, recompletion and tie-in of wells, tax horizon, timing of development of undeveloped reserves, planned capital expenditures, the timing thereof and the method of funding may be forward looking statements which reflect management's expectations regarding future plans and intentions, growth, results of operations, performance and business prospects and opportunities. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions have been used to identify these forward looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward looking statements including, but not limited to, changes in general economic and market conditions, 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 and risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserve estimates of Galleon's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the foregoing list of factors is not exhausted. Additional information on these and other factors that could effect Galleon's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), and at Galleon's website (www.gallenergy.com). Although the forward looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward looking statements. Investors should not place undue reliance on forward looking statements. These forward looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward looking statements and other information contained herein concerning the oil and gas industry and the Corporation's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Corporation believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Corporation is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

BACKGROUND

Galleon Energy Inc. was incorporated under the ABCA on March 27, 2003. On June 6, 2003, the Articles of the Corporation were amended to create the Class A Shares and the Class B Shares. On July 21, 2003, the Articles of Galleon were amended to (i) increase the minimum number of directors from one to three; (ii) remove restrictions on the transferability of its shares; and (iii) remove the limit on the number of shareholders of the Corporation and the prohibition on the Corporation making an invitation to publicly subscribe for securities. On January 1, 2005, the Corporation amalgamated with its wholly-owned subsidiaries, Venture Energy Inc. ("Venture") and Inisfail Energy Ltd. ("Inisfail") and continued under the name Galleon Energy Inc. On June 7, 2006, the Articles of Galleon were amended to subdivide the issued and outstanding Class A Shares on a three-for-two basis. The number and price of Galleon's shares in this annual information form for periods prior to June 2006 have been re-stated to reflect the subdivision.

Unless the context otherwise requires, reference herein to "Galleon", the "Company" or the "Corporation" means Galleon Energy Inc. At December 31, 2007, Galleon did not have any subsidiaries, other than 1244419 Alberta Ltd., which has no material assets or liabilities, and other than 1175176 Alberta Ltd., an Alberta corporation which is wholly-owned by Galleon and is a 0.1% in Galleon Energy Partnership (an Alberta general partnership of which Galleon is a 99.9% partner). Galleon Energy Partnership holds Galleon's producing oil and gas assets. Subsequent to December 31, 2007, Galleon acquired all of the outstanding shares of ExAlta, a corporation incorporated under the laws of Alberta (see "Recent Developments").

Galleon's principal office is located at 500, 311 – 6th Avenue S.W., Calgary, Alberta, T2P 3H2 and its registered office is located at 1400, 350 - 7th Avenue S.W., Calgary, Alberta, T2P 3N9.

The Class A Shares and Class B Shares of Galleon trade on the TSX under the symbols "GO.A" and "GO.B", respectively.

GENERAL DEVELOPMENT OF THE BUSINESS

The following is a summary of the business operations of the Corporation for the periods shown.

2005

On February 10, 2005, Galleon closed a private placement for gross proceeds of $45 million. In total, 6,338,033 Class A Shares were issued at $7.10 each.

On May 12, 2005, Galleon closed financings for gross proceeds of $57.94 million. In total, 5,691,000 Subscription Receipts were issued at $6.67 each for gross proceeds of $37,940,000. Each Subscription Receipt entitled the holder to receive one Class A Share of Galleon, without the payment of any additional consideration, upon the closing of Galleon's acquisition of oil and gas assets in the Peace River Arch area of Alberta which was announced on April 4, 2005 (the "Dawson Acquisition"). Proceeds from the issuance of the Subscription Receipts were placed in escrow and were released in connection with the closing of the Dawson Acquisition which occurred on May 18, 2005. In addition, 2,400,000 Class A Shares were issued on a flow through basis (the "Flow-Through Shares") at $8.33 each for gross proceeds of $20,000,000. The Flow-Through Shares, the Subscription Receipts and the Class A Shares issuable pursuant to the Subscription Receipts were subject to a hold period under applicable securities laws which expired September 13, 2005.

On May 18, 2005, Galleon closed the Dawson Acquisition which was purchased from an arm's length party for cash of $89.8 million including closing adjustments. The properties are located in the center of Galleon's core areas of Dawson and Calais in the Peace River Arch area of Alberta. The purchase included daily production of approximately 2,100 BOE (60% light sweet oil, 40% natural gas); the remaining working interest in the existing Galleon operated gas plants and gathering systems in the Dawson area; 100% working interest in three additional gas plants; 85% working interest in and operatorship of a large oil battery and approximately 147,000 net acres of undeveloped land.

On September 6, 2005, the Class A Shares and Class B Shares of Galleon commenced trading on the TSX.

During 2005 Galleon drilled 39.5 net natural gas wells and 14.5 net oil wells. The average production rate for the year was 6,539 BOE/day. Capital expenditures during 2005 were $106.9 million plus property acquisitions of $103.5 million.

2006

On February 14, 2006, Galleon closed a private placement of 3,405,000 Class A Shares issued at a price of $16.17 per share for gross proceeds of approximately $55 million.

On March 9, 2006, Galleon announced a major light sweet oil discovery in the Puskwa, Alberta area of the Peace River Arch.

On June 19, 2006, Galleon announced a second major light sweet oil discovery in the Puskwa, Alberta area of the Peace River Arch. The well (100% interest), located at 12-11-72-26 W5M, was drilled three miles from the 16-32 well with rig release on June 11, 2006.

On July 25, 2006 Galleon closed a public offering of 2,985,000 Class A Shares issued at a price of $20.15 per Class A Share and 7,800 Class A Shares issued on a "flow-through" basis at a price of $25.70 per share for aggregate gross proceeds of $80,193,750.

On September 5, 2006, Galleon announced its third major light sweet oil discovery in the Puskwa, Alberta area of the Peace River Arch. The well (100% interest), located at 16-11-72-26 W5M, was drilled four miles from the first major well at 16-32 with rig release on August 26, 2006.

On November 16, 2006, Galleon closed a public offering of 1,025,700 Class A Shares issued at a price of $19.50 per share and 800,000 Class A Shares issued on a "flow-through" basis at a price of $25.00 per share for aggregate gross proceeds of approximately $40 million.

During 2006 Galleon drilled 59.9 net natural gas wells and 28.1 net oil wells. The average production rate for the year was 9,370 BOE/day. Capital expenditures during 2006 were $283.3 million plus property acquisitions of $25.4 million.

2007

Effective February 1, 2007 Galleon purchased a 99.9% interest in the Galleon Energy Partnership and the corporation holding the remaining 0.01% interest, for total cash consideration of $28.6 million. When acquired, the partnership held oil and gas assets within Galleon's core area of Dawson, Alberta.

On March 23, 2007 Galleon was granted good production practice status by the EUB on section 32-71-26 W5M and section 5-72-26 W5M at Puskwa and Galleon advised that it would proceed with a pilot waterflood.

On April 19, 2007 Galleon closed a private placement of 1,481,500 Class A Shares issued on a "flow-through" basis at a price of $20.25 per share for gross proceeds of approximately $30 million.

On September 13, 2007, Galleon announced it had received EUB approval granting enhanced recovery (waterflood) approval and good production practice status on a portion of Sections 11 and 13-72-26 W5M in the Puskwa area.

On September 28, 2007, Galleon closed a public offering of 1,869,200 Class A Shares issued at a price of $16.05 per share and 1,463,400 Class A Shares issued on a "flow-through" basis at a price of $20.50 per share for aggregate gross proceeds of approximately $60 million.

On October 25, 2007, the Alberta government released the New Royalty Framework pertaining to royalties on oil and gas resources including oil sands, conventional oil and gas and coalbed methane. The NRF is scheduled to take effect on January 1, 2009. The NRF was the Alberta government's response to the recommendations put forth by the Alberta Royalty Review Panel. Given the methodology used in the proposed royalty regime, the effect on Galleon's cash flow will be affected by depths and productivity of wells. The actual effect of the Alberta royalty rate changes on Galleon will be determined based on, among other things, the actual legislation enacted, the production rates, commodity prices, foreign exchange rates, production mix, service costs and the percentage of production from Alberta after January 1, 2009. See Note 7 under "Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data – Reserves Data (Forecast Prices and Costs)" for information relating to sensitivities relating to the possible impact of the NRF and see "Risk Factors".

RECENT DEVELOPMENTS

On January 16, 2008, Galleon completed the acquisition of all of the outstanding shares of ExAlta, for aggregate consideration of approximately $110.4 million, comprised of the issuance of approximately 4.335 million Class A Shares and the assumption of approximately $47.9 million of net debt. Prior to the acquisition, ExAlta's common shares were listed on the TSX and it was a reporting issuer in various provinces of Canada. At the time of acquisition, ExAlta's production was approximately 2,200 boe/d (approximately 44% oil and 56% natural gas). The principal properties of ExAlta are Alexis-Cherhill, Clayhurst and Eaglesham, Alberta. Further information in respect of ExAlta is included in Schedule "D" hereto and in the ExAlta BAR filed by the Corporation in respect of the acquisition of ExAlta which is available on SEDAR at www.sedar.com.

Galleon has a 2008 capital expenditure program of between $200 million and $210 million depending on commodity prices and market conditions. In 2008, Galleon currently plans to drill up to 118 wells. The 2008 drilling program including 68 oil (mainly light oil) and 50 natural gas wells.

On March 12, 2008, Galleon announced an agreement to purchase all of the outstanding shares of a non-listed company for aggregate consideration of approximately $67.2 million including positive working capital of approximately $3.8 million. The acquisition price will be paid by the issuance of approximately 4 million Class A Shares of Galleon. The acquisition will add proved plus probable reserves of 4.2 million BOE and over 1,500 BOE/day of production (85% gas, 15% oil). The acquisition will be completed by way of a plan of arrangement and is subject to receipt of approval by not less than 66 2/3% of the shareholders of the non-listed company that vote on the resolution, court approval and required regulatory approvals. The acquisition is expected to close prior to the end of May 2008.

DESCRIPTION OF THE BUSINESS AND OPERATIONS

Exploration and Development Strategy

The business plan of Galleon is to create value on a production and reserve per share basis in the oil and gas industry in western Canada. To accomplish this, Galleon has pursued and will continue to pursue an integrated growth strategy including focused exploration, controlled exploitation and strategic acquisitions within its geographic project areas in the Peace River Arch region of the Western Canadian Sedimentary Basin.

Galleon will focus on exploration and development drilling in the Peace River Arch area of Alberta and British Columbia. Galleon has assembled large land blocks close to gas infrastructure and crude oil processing facilities. Galleon has invested in natural gas and crude oil infrastructure in its key areas so as to obtain operatorship and control of the facilities. Additionally, Galleon has pursued and will continue to pursue strategic asset and corporate acquisitions of crude oil and natural gas properties.

Galleon plans to pursue the internal and external generation of exploration plays that have low to medium risk and multi-zone potential. In addition, the exploration for higher risk targets is included in the plan, but to a limited extent. Galleon plans to maintain a balance between exploration, exploitation and development drilling largely targeting natural gas reserves and light sweet crude oil over the course of the next five years. Management of Galleon will consider asset and corporate acquisition opportunities that meet Galleon's business parameters. While Galleon believes that it has the skills and resources necessary to achieve its stated objectives, participation in the exploration for and development of oil and natural gas has a number of inherent risks.

Management of Galleon has industry experience in producing areas in western Canada in addition to its initial geographic areas of interest and has the capability to expand the scope of Galleon's activities as opportunities arise.

In reviewing potential participations or acquisitions, Galleon will consider criteria including the following:

- the ratio of risk to reward;
- whether the opportunity has an anticipated pay-back period of less than two years;
- whether the opportunity has an anticipated rate of return of greater than 30%;
- whether the area possesses geological opportunities that have multi-zone potential;
- whether the prospects have reservoir characteristics that are familiar to management;
- the amount of potential for additional reservoir development;
- the degree of near term market access;
- whether sufficient infrastructure exists to provide for increased activity;
- whether there are investments in a sufficient number of properties to reduce risk;
- whether the properties exhibit reserve life of at least six years;
- the possibility of Galleon becoming the operator; and
- the ability of Galleon to enhance the value of acquired properties through additional exploitation efforts, including improved production practices, additional development drilling, completion and tie-in of capped wells and improved marketing arrangements.

In addition to the above criteria, in circumstances where Galleon seeks to acquire significant assets with proven reserves, prior to the investment decision being finalized Galleon will generally obtain an independent engineering report (whether from the vendor of such assets or otherwise) relating to such proven reserves.

The Board of Directors of Galleon may, in its discretion, approve asset or corporate acquisitions or investments that do not conform to these guidelines based upon its consideration of the qualitative aspects of the subject properties including risk profile, technical upside, reserve life and asset quality.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Reserves Data and Other Information

The Corporation engaged DeGolyer to provide an evaluation of the Corporation's proved and proved plus probable reserves as at December 31, 2007. The reserves data set forth below (the "Reserves Data") is based upon the DeGolyer Report. The date of preparation of the DeGolyer Report is March 12, 2008. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs. The DeGolyer Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. The Reserves Committee of the Board of Directors has reviewed and approved the DeGolyer Report. The Report of Management and Directors on Oil and Gas Disclosure and the Report on Reserves Data by the Independent Qualified Reserves Evaluator are attached as Schedules "A" and "B" hereto, respectively.

All of the Corporation's reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia and Saskatchewan.

The Disclosure of Reserves Data contained herein does not include information with respect to the oil and gas properties and reserves of ExAlta, which was acquired by the Corporation effective January 16, 2008. Such information is included in Schedule "D" hereto The ExAlta BAR filed by the Corporation in respect of the acquisition of ExAlta is available on SEDAR at www.sedar.com.

All evaluations of future net production revenue set forth in the tables below are based on forecast prices and costs and are after direct lifting costs, normal allocated overhead and future capital investments. It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of the Corporation's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2007
FORECAST PRICES AND COSTS

	RESERVES									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (MBOE)	Net (MBOE)
Proved Developed										
Producing	5,920	4,675	1,751	1,393	44,515	34,019	275	186	15,365	11,924
Non-Producing	1,193	963	820	680	18,605	13,612	139	90	5,253	4,002
Proved Undeveloped	3,454	2,803	4,129	3,368	34,119	26,714	197	132	13,467	10,755
Total Proved	10,567	8,441	6,700	5,441	97,239	74,345	611	408	34,085	26,681
Probable	11,259	8,887	4,692	3,719	54,298	41,270	389	260	25,388	19,744
Total Proved plus Probable	21,826	17,328	11,392	9,160	151,537	115,615	1,000	668	59,473	46,425

	NET PRESENT VALUES OF FUTURE NET REVENUE										
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year
RESERVES CATEGORY	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	($/BOE)
Proved Developed											
Producing	510	443	394	356	326	510	443	394	356	326	33.05
Non-Producing	140	110	90	76	65	133	104	85	71	61	22.46
Proved Undeveloped	309	214	155	116	90	233	156	111	81	61	14.41
Total Proved	959	766	639	548	480	875	703	589	508	448	23.95
Probable	848	615	473	376	307	622	447	341	269	218	23.95
Total Proved plus Probable	1,807	1,382	1,112	925	788	1,497	1,150	930	778	666	23.95

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2007
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (MM$)	ROYALTIES (MM$)	OPERATING COSTS (MM$)	DEVELOPMENT COSTS (MM$)	WELL ABANDONMENT COSTS (MM$)	FUTURE NET REVENUE BEFORE INCOME TAXES (MM$)	INCOME TAXES (MM$)	FUTURE NET REVENUE AFTER INCOME TAXES (MM$)
Total Proved	2,029	389	541	111	30	959	84	875
Total Proved plus Probable	3,691	727	913	207	37	1,807	310	1,497

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2007
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (MM$)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year ($/Bbl) ($/Mcf)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	382	$39.42/Bbl
	Heavy Oil (including solution gas and other by-products)	50	$9.27/Bbl
	Natural Gas (including by-products but excluding solution gas from oil wells)	207	$2.98/Mcf
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	735	$37.35/Bbl
	Heavy Oil (including solution gas and other by-products)	84	$9.14/Bbl
	Natural Gas (including by-products but excluding solution gas from oil wells)	293	$2.78/Mcf

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the DeGolyer Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

   Reserve Categories

   Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

   - analysis of drilling, geological, geophysical and engineering data;
   - the use of established technology; and
   - specified economic conditions, specifically the forecast prices and costs.

Reserves are classified according to the degree of certainty associated with the estimates.

(a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(c) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

  (i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

  (ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(d) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserve estimates are prepared). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the estimated proved plus probable reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

3. Forecast Costs and Price Assumptions

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by DeGolyer in the DeGolyer Report were DeGolyer's forecasts, as at December 31, 2007, as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

	OIL							
Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Oil Price 40° API ($Cdn/Bbl)	Hardisty Heavy 12° API ($Cdn/Bbl)	Natural Gas Alberta Spot Gas Price ($Cdn/Mcf)	Pentanes Plus Edmonton ($Cdn/Bbl)	Butanes Price Edmonton ($Cdn/Bbl)	Inflation Rates(1) %/Year	Exchange Rate(2) ($US/$Cdn)
Forecast								
2008	90.00	89.50	63.55	6.69	91.29	71.60	0.0	1.00
2009	86.52	86.01	61.06	7.29	87.73	64.50	3.0	1.00
2010	84.87	84.34	59.88	7.18	86.03	63.26	3.0	1.00
2011	83.32	82.78	58.78	7.13	84.44	62.09	2.0	1.00
2012	82.78	82.23	58.38	7.19	83.87	61.67	2.0	1.00
2013	82.19	81.62	58.36	7.21	83.26	61.22	2.0	1.00
2014	81.53	80.96	58.29	7.35	82.58	60.72	2.0	1.00
2015	81.99	81.41	59.02	7.49	83.03	61.06	2.0	1.00
2016	83.63	83.03	60.62	7.64	84.70	62.28	2.0	1.00
2017	85.30	84.70	61.83	7.78	86.39	63.52	2.0	1.00
2018	87.01	86.39	63.06	7.97	88.12	64.79	2.0	1.00
2019	88.75	88.12	64.33	8.17	89.88	66.09	2.0	1.00
2020+	Escalated oil, gas and product prices at 2% per year thereafter							

Notes:

(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by the Corporation for the year ended December 31, 2007, were $6.54/Mcf for natural gas, $74.77/Bbl for light crude oil, $37.39/Bbl for heavy oil and $63.94/Bbl for NGLs.

4. Well abandonment costs for wells with reserves have been included at the property level. Additional abandonment costs associated with non-reserves wells, lease reclamation costs and facility abandonment and reclamation expenses have not been included in this analysis.

5. The forecast price and cost assumptions assume the continuance of current laws and regulations.

6. The extent and character of all factual data supplied to DeGolyer were accepted by DeGolyer as represented. No field inspection was conducted.

7. Sensitivity to the New Alberta Royalty Framework

Corporate total economic forecasts were rerun to examine the impact of the NRF. The government has not yet clarified certain aspects of the new royalty calculations. Accordingly, high and low sensitivities to the

NRF were conducted using the Consultant's Consensus Methodology recommended by the Society of Petroleum Evaluation Engineers, Calgary Chapter. The "NRF High" scenario represents a more optimistic or high value sensitivity of the NRF impact, and the "NRF Low" scenario represents the low value sensitivity. Based on currently available information, the net present value of future net revenue (before income taxes) of proved and probable reserves as at December 31, 2007, based on the NRF High scenario would be $933 million and based on the NRF Low scenario would be $921 million The government has stated its intention to consult with industry and review the NRF for unintended consequences.

Reconciliations of Changes in Gross Reserves

RECONCILIATION OF
COMPANY GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL			HEAVY OIL		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
December 31, 2006	7,949	10,012	17,961	7,622	5,016	12,638
Extensions	86	898	984	67	62	129
Improved Recovery	0	0	0	0	0	0
Technical Revisions	1,825	(4,891)	(3,067)	(350)	(855)	(1,205)
Discoveries	1,395	4,890	6,285	0	330	330
Acquisitions	412	231	644	0	100	100
Dispositions	(1)	0	(1)	0	0	0
Economic Factors	202	119	322	91	39	130
Production	(1,301)	0	(1,301)	(730)	0	(730)
December 31, 2007	10,567	11,259	21,826	6,700	4,691	11,392

	NATURAL GAS LIQUIDS			CONVENTIONAL NATURAL GAS			TOTAL		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (MBOE)	Gross Probable (MBOE)	Gross Proved Plus Probable (MBOE)
December 31, 2006	365	257	622	74,169	40,974	115,143	28,298	22,113	50,412
Extensions	48	56	104	16,928	16,022	32,950	3,023	3,686	6,708
Improved Recovery	0	0	0	0	0	0	0	0	0
Technical Revisions	114	(33)	81	3,207	(10,644)	(7,437)	2,123	(7,553)	(5,430)
Discoveries	134	100	233	14,488	7,026	21,514	3,943	6,491	10,434
Acquisitions	40	9	49	5,931	977	6,908	1,441	503	1,944
Dispositions	(1)	0	(1)	(953)	(57)	(1,010)	(161)	(10)	(170)
Economic Factors	0	0	0	0	0	0	293	158	452
Production	(90)	0	(90)	(16,531)	0	(16,531)	(4,876)	0	(4,876)
December 31, 2007	611	389	1,000	97,239	54,298	151,537	34,085	25,388	59,473

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the remaining proved undeveloped reserves and the remaining probable undeveloped reserves, each by product type, attributed to Galleon's assets for the years ended December 31, 2007, 2006 and 2005 and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	0	0	0	0	0	0	0	0
2005	9	9	4,015	4,015	1,989	1,989	7	7
2006	1,336	1,345	47	4,062	16,851	18,840	80	87
2007	2,109	3,454	119	4,181	15,013	33,853	111	198

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	49	49	0	0	276	276	0	0
2005	2	51	2,602	2,602	840	1,116	1	1
2006	1,878	1,928	3	2,605	7,727	8,843	53	54
2007	5,040	6,968	14	2,620	19,258	28,101	127	181

In general, once proved and/or probable undeveloped reserves are identified they are scheduled into Galleon's development plans. Normally, the Corporation plans to develop its proved and probable undeveloped reserves within two years. A number of factors that could result in delayed or cancelled development are as follows:

- changing economic conditions (due to pricing, operating and capital expenditure fluctuations);
- changing technical conditions (production anomalies (such as water breakthrough, accelerated depletion));
- multi-zone developments (such as a prospective formation completion may be delayed until the initial completion is no longer economic);
- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and
- surface access issues (landowners, weather conditions, regulatory approvals).

See "Principal Properties", "Future Development Costs" and "Capital Expenditures" for a description of the Corporation's exploration and development plans and expenditures.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

The Corporation does not anticipate any unusually high development costs or operating costs, the need to build a major pipeline or other major facility before production of reserves can begin, or contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

Future Development Costs

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserve categories noted below:

Year	Forecast Prices and Costs (MM$)	
	Proved Reserves	Proved Plus Probable Reserves
2008	23	45
2009	33	56
2010	26	55
2011	8	17
2012	4	6
Thereafter	17	27
Total Undiscounted	111	206

On an ongoing basis, Galleon will use internally generated cash flow from operations, debt and new equity issues if available on favourable terms to finance its capital expenditure program. The cost of funding is not expected to have any effect on disclosed reserves or future net revenue nor make the development of a property uneconomic for the Corporation

Other Oil and Gas Information

Principal Properties

The Corporation is engaged in the exploration for and development and production of crude oil and natural gas in Western Canada. All of the Corporation's current operations are in the provinces of Saskatchewan, Alberta and British Columbia.

The following is a description of the Corporation's oil and natural gas properties as at December 31, 2007, unless otherwise stated. The following descriptions do not include a description of the properties acquired by the Corporation effective January 16, 2008 through the acquisition of ExAlta. Descriptions of ExAlta's properties are provided in Schedule "D" hereto. Production stated is gross production to the Corporation and, unless otherwise stated, is average daily production during February 2008 based on field estimates. The reserve amounts stated are gross reserves, as at December 31, 2007 based on forecast costs and prices as evaluated in the DeGolyer Report (see "Reserves Data"). **The estimates of reserves and future net revenue for individual properties may not reflect**

the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Calais, Alberta

The Calais property is located in Townships 71 to 78, and Ranges 21 W5M to 3 W6M, and is approximately 25 miles northeast of Grande Prairie, Alberta. Calais consists of the Puskwa, Eaglesham, Kakut, Kakut West, Peoria, and Rycroft areas.

The Puskwa property is located in Townships 71 to 73, and Ranges 25 W5M to 1 W6M. Galleon is the operator of the wells and facilities, with an approximate 96% average working interest in the producing wells. The area is characterized by high quality light sweet crude oil at approximately 3,100 meters depth. The primary zone lies within the Devonian age Beaverhill Lake Formation. Other potential oil and natural gas zones occur in the shallower Cretaceous Dunvegan formation to the Mississippian Debolt formation with depths ranging from 650 meters to 1900 meters respectively. Approximately 65% of this area has year round access for drilling, seismic and construction projects.

The Eaglesham property is located in Townships 76 to 77, and Ranges 25 W5M to 1 W6M. Galleon is the operator of the wells and facilities, with an approximate 75% average working interest in the producing wells. The area is characterized by high quality multi-zone light oil and liquids-rich natural gas formations at depths ranging from 350 meters to 2300 meters. Galleon has identified twelve target zones: Dunvegan, Paddy, Notikewin, Gething, Charlie Lake, Montney, Kiskatinaw, Debolt, Banff, Wabamun, and Granite Wash. Approximately 85% of this area is year round accessible for drilling, seismic and construction projects.

During 2007 Galleon drilled 35 (32.5) net wells and cased 32 (30.3 net) wells at Calais. Galleon plans to drill up to 60 wells in 2008 in the Calais area. At February 29, 2008, there were 53 (42.5 net) wells on production. February 2008 average production was approximately 16.0 MMcf/d and 3,750 Bbls/d of oil and NGLs, based upon field estimates. At December 31, 2007, the Corporation had an interest in 147,299 gross acres (115,965 net acres) of undeveloped land in the Calais area.

The DeGolyer Report assigns total proved reserves of 9.1 MMbbls of oil and NGLs and 35.3 Bcf of natural gas, and total proved plus probable reserves of 18.8 MMbbls of oil and NGLs and 59.7 Bcf of natural gas.

Dawson, Alberta

The Dawson property is located in Townships 74 to 85, and Ranges 10 to 24, W5M, and approximately 100 miles northeast of Grande Prairie, Alberta. The Dawson area consists of several smaller properties detailed in the DeGolyer Report including Harmon Valley, Roxana, Roxana Non-Op, Dawson, Lalby, Kimiwan, Dreau, Heart River, Donnelly/Kenzie, Falher, Tangent, Slave, Seal, Gift, Shadow, West Culp, McLeans Creek, Springburn and Gage.

The Dawson Montney gas play is located in Townships 74 to 78 and Ranges 19 to 21 W5M. Galleon is the operator of the wells and facilities. The area is characterized mainly by six to 30 meter thick tight gas pay zones at approximately 900 meters depth. This zone lies within the Triassic age Montney formation. All of this area is year round accessible for drilling, seismic and construction projects.

The average working interest in the producing wells in the Dawson area is approximately 85%. The area is characterized by high quality and multi-zone natural gas formations at depths ranging from 300 m to 2400 m. Galleon has identified ten target zones: Paddy, Notikewin, Falher, Bluesky, Gething, Charlie Lake, Montney, Debolt, Beaverhill Lake, Granite Wash and Slave Point. Light oil also exists in some of these formations. About 80% of the area has year round access for drilling, seismic and construction projects.

During 2007 Galleon drilled 53 (49.6 net) wells and cased 46 (43.9 net) wells at Dawson. Galleon plans to drill up to 50 wells in 2008. At February 29, 2008, there were 181 (155.6 net) wells on production at Dawson. February 2008 average production was approximately 28.2 MMcf/d and 2,005 Bbls/d of oil and NGLs, based on field estimates. At December 31, 2007, the Corporation had interest in 457,949 gross acres (393,931 net acres) of undeveloped land.

The DeGolyer Report assigns total proved reserves of 1.8 MMbbls of oil and liquids and 57.4 Bcf of natural gas, and total proved plus probable reserves of 4.2 MMbbls of oil and liquids and 83.5 Bcf of natural gas.

Edam, Saskatchewan

The Edam property is located in Townships 47 to 49, and Ranges 18 and 19 W3M, and is approximately 50 miles east of Lloydminster, Saskatchewan. Galleon acquired these assets during 2005. Galleon is the operator of the wells and has an approximate 99% working interest in the producing wells. The area is characterized by high quality sandstone reservoirs in the Cretaceous Mannville formation at depths of 400 m to 500 m. Galleon's primary target for development and production is heavy oil in the Waseca sandstone which lies within the Mannville formation. Natural gas also exists in some of these formations. The area has year round access for drilling, seismic and construction projects.

During 2007 Galleon drilled 4 (3.1 net) wells and cased 4 (3.1 net) wells for oil production at Edam. In addition, in 2007, 1 (1,0 net) wells were drilled and cased for natural gas production. At December 31, 2007, there were 34 (33 net) wells on productionat Edam. February 2008 average production was approximately 1,750 Bbls/d of oil, based upon field estimates. At December 31,, 2007, the Corporation had an interest in 18,041 gross acres (18,041 net acres) of undeveloped land at Edam.

The DeGolyer Report assigns total proved reserves of 6.6 MMbbls of oil, and total proved plus probable reserves of 10.7 MMbbls.

Minor Properties

Wymark, Saskatchewan

The Wymark property is located in Townships 13-14 and Range 13 W3M approximately 140 miles west of Regina, Saskatchewan. Galleon has a 100% working interest in the producing wells. The property produces natural gas from shallow depths.

In February 2008, the property was producing approximately 0.7 MMcf/d from 29 wells based on field estimates. At December 31, 2007, the Corporation had an interest in 2,560 gross acres (2,560 net acres) of undeveloped land. There are no current plans to drill wells at Wymark in 2008.

The DeGolyer Report assigns total proved reserves of 1.9 Bcf of natural gas and total proved plus probable reserves of 2.9 Bcf of natural gas.

Two Rivers and Flatrock, British Columbia

These properties are located in Townships 83-84 and Ranges 14-16 W6M approximately 20 miles east of Fort St. John, British Columbia. Galleon has an average producing working interest of approximately 65%. The properties produce natural gas, crude oil and NGLs.

At December 31, 2007 the Corporation had an interest in 13,644 gross acres (11,050 net acres) of undeveloped land.

The DeGolyer Report assigns total proved reserves of 1.4 Bcf of natural gas and 127 Mbbls of crude oil and NGLs and total proved plus probable reserves of 4.0 Bcf of natural gas and 156 Mbbls of crude oil and NGLs.

Other

The Corporation has interests in other properties including Barthel, Balwinton, Delta West, Hoosier, Lloydminster, Lashburn, and Tompkins Saskatchewan, Boundary Lake and Paradise, British Columbia and Abee, Bindloss, Doe Creek, John Lake, Monitor, Lloydminster, Wainwright, Karr, Princess and Progress, Alberta. In aggregate, total proved reserves of 1.1 Bcf of natural gas and 221 Mbbls of crude oil and NGLs and total proved plus probable reserves of 1.4 Bcf of natural gas and 435 Mbbls of oil and NGLs were assigned by DeGolyer to these properties. The Corporation has no current plans to drill on these properties in 2008. At December 31, 2007, Galleon has interests in approximately 23,805 gross acres (17,022 net acres) of undeveloped land in these areas.

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Corporation had a working interest as at December 31, 2007.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	154	128.2	58	32.2	217	181.4	125	101.9
British Columbia	6	2.6	1	0.6	5	2.8	24	17.3
Saskatchewan	55	54.4	103	80.6	31	30.1	8	7.8
Total	215	185.2	162	113.4	253	214.3	157	127.0

Properties with no Attributable Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2007.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	197,117	150,551	619,120	519,525	816,237	670,076
British Columbia	17,016	8,670	14,304	11,248	31,320	19,918
Saskatchewan	19,008	17,006	29,874	27,796	48,882	44,802
Total	233,141	176,227	663,298	558,569	896,439	734,796

The Corporation expects that rights to explore, develop and exploit 90,396 net acres of its undeveloped land holdings will expire by December 31, 2008, a portion of which may be continued by drilling. Galleon plans to drill or submit application to continue selected portions of the above acreage.

Forward Contracts and Marketing

Galleon's crude oil and natural gas production is sold to major Canadian marketers on a spot pricing basis. Terms of the agreements include a 30 day evergreen in the case of crude oil and NGLs and a term of one year for natural gas. Galleon may periodically hedge the price of a portion of its crude oil and natural gas production. The Corporation contracts natural gas transportation for periods of one to five years at volumes based on estimated production from each property.

As of the date hereof, the Corporation has the following fixed price physical contracts in place:

Natural Gas:		
February 1, 2008 – December 31, 2008	10,000 GJ/day	CDN $6.00-$8.00 GJ

As of the date hereof, the Corporation has the following costless collar financial derivative in place:

Crude Oil:		
January 1, 2008 – December 31, 2008	2,000 Bbl/d	WTI CDN $70.00-$80.75/Bbl
January 1, 2008 – December 31, 2008	1,000 Bbl/d	WTI USD $75.00-$100.00/Bbl

Additional Information Concerning Abandonment and Reclamation Costs

Estimated future abandonment costs related to a property have been taken into account by DeGolyer in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom. The Corporation uses its internal historical costs to estimate its abandonment and reclamation costs when available. The costs are estimated on an area by area basis. The industry's historical costs are used when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements. The Corporation has 679 net wells for which it expects to incur abandonment and reclamation costs. The abandonment and reclamation obligation included in the Corporation's financial statements differs from the amount deducted in the reserves evaluation, as no allowance was made for reclamation of wellsites or the abandonment and reclamation of any facilities in the DeGolyer Report. The following table sets forth abandonment costs deducted in the estimation of the Corporation's future net revenue:

Forecast Prices and Costs (MM$)

Year	Total Proved Abandonment Costs (Undiscounted)	Total Proved plus Probable Abandonment Costs (Undiscounted)
2008	1	1
2009	1	1
2010	10	10
Thereafter	18	25
Total Undiscounted	30	37
Total Discounted @ 10%	16	16

Tax Horizon

The Corporation does not expect to pay current income tax for the 2008 fiscal year. Depending on production, commodity prices and capital spending levels, the Corporation may begin paying current income taxes in 2009.

Capital Expenditures

The following table summarizes capital expenditures related to the Corporation's activities for the year ended December 31, 2007:

	(M$)
Property acquisition costs	
Proved properties	52,082
Undeveloped properties	10,789
Exploration costs	44,480
Development costs	153,075
Dispositions	-
Total	260,426

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Corporation participated during the year ended December 31, 2007:

	Exploratory Wells		**Development Wells**	
	Gross	**Net**	**Gross**	**Net**
Light and Medium Oil	9	8.6	20	18.1
Heavy Oil	-	-	5	3.6
Natural Gas	8	7.5	41	37.0
Dry	8	6.8	2	1.2
Total	25	22.9	68	59.9

See "Principal Properties" for a description of the Corporation's exploration and development plans.

Galleon's primary area of exploration and development activity is in the Peace River Arch area of Alberta. Galleon's key growth areas of Puskwa, Eaglesham, and Dawson Montney gas are located in this area. In 2007, 12 wells were drilled at Puskwa, 15 at Eaglesham, and 32 Montney gas wells at Dawson. The majority of capital expenditures in 2008 are currently planned to be invested in these three areas. See "Principal Properties".

Production Estimates

The following tables disclose, by product, the total volume of the Corporation's gross production estimated by DeGolyer for 2008 in the estimates of future net revenue from gross proved and gross probable reserves disclosed under "Disclosure of Reserves Data and Other Information"

From Gross Proved reserves:	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)	%
Puskwa	2,808	-	3,611	82	3,492	22
Eaglesham	951	-	11,803	66	2,984	19
Dawson Montney gas	182	-	11,252	52	2,110	13
Edam	-	1,652	16	0	1,655	11
Dreau	324	-	4,592	16	1,105	7
Other	1,250	123	17,140	63	4,293	28
Total	5,514	1,775	48,414	280	15,638	100

From Gross Probable reserves:	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)	%
Puskwa	82	-	79	3	98	4
Eaglesham	534	-	1,271	22	768	33
Dawson Montney gas	26	-	764	4	157	7
Edam	-	197	3	-	198	9
Dreau	21	-	323	1	76	3
Other	466	58	2,718	39	1,015	44
Total	1,129	255	5,159	68	2,311	100

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	Quarter Ended			
	2007			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production[(1)]				
Light and Medium Crude Oil (Bbls/d)	4,419	3,375	3,317	3,126
Heavy Oil (Bbls/d)	1,746	1,949	2,247	2,082
Gas (Mcf/d)	49,486	48,989	45,314	38,845
NGLs (Bbls/d)	283	237	256	206
Combined (BOE/d)	14,695	13,726	13,372	11,888

	Quarter Ended 2007			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Price Received (net of transportation)				
Light and Medium Crude Oil ($/Bbl)	83.38	78.43	70.13	63.24
Heavy Oil ($/Bbls)	37.32	40.04	35.90	36.55
Gas ($/Mcf)	6.16	5.73	7.14	7.36
NGLs ($/Bbls)	72.90	64.05	59.67	56.64
Combined ($/BOE)	51.59	46.51	48.75	48.04
Royalties Paid				
Light and Medium Crude Oil ($/Bbls)	15.89	15.25	15.39	9.54
Heavy Oil ($/Bbls)	7.82	8.67	7.41	7.46
Gas ($/Mcf)	1.35	1.32	1.72	1.91
NGLs ($/Bbls)	19.76	17.93	14.72	14.52
Combined ($/BOE)	10.62	9.98	11.18	10.30
Operating Expenses ($/BOE)				
Light and Medium Crude Oil ($/Bbls)	8.72	6.18	7.09	7.02
Heavy Oil ($/Bbls)	27.10	21.88	18.23	18.85
Gas ($/Mcf)	1.91	1.35	1.47	1.52
NGLs ($/Bbls)	7.85	5.82	6.19	6.29
Combined ($/BOE)	10.52	8.35	8.63	8.86
Netback Received ($/BOE)(2)				
Light and Medium Crude Oil ($/Bbls)	58.77	57.00	47.65	46.68
Heavy Oil ($/Bbls)	2.40	9.49	10.26	10.24
Gas ($/Mcf)	2.90	3.06	3.95	3.93
NGLs ($/Bbls)	45.29	40.30	38.76	35.83
Combined ($/BOE)	30.45	28.18	28.94	28.88

Notes:

(1) Before deduction of royalties.
(2) Netbacks are calculated by subtracting royalties and operating costs from revenues.

The following table indicates the Corporation's average daily production from its important fields for the year ended December 31, 2007:

	Light and Medium Crude Oil (Bbls/d)	Heavy Oil (Bbls/d)	Gas (Mcf/d)	NGLs (Bbls/d)	BOE (BOE/d)
Puskwa	1,787	-	1,461	95	2,125
Dawson Montney gas	310	-	18,183	64	3,406
Eaglesham	397	-	8,023	29	1,763
Dawson	947	-	12,331	23	3,025
Calais	60	-	3,765	28	715
Edam and other heavy oil	-	2,005	-	-	2,005
Other	61	-	1,934	7	390
Total	3,562	2,005	45,697	246	13,429

The Corporation's crude oil production for the year ended December 31, 2007 was 26% light quality crude oil (32° API or greater), 15% heavy oil, 57% natural gas, and 2% liquids.

For the twelve months ended December 31, 2007, approximately 51% of the Corporation's gross revenue was derived from crude oil production and 49% was derived from natural gas production.

DIVIDEND POLICY

Galleon has not paid any dividends on the outstanding Class A Shares or Class B Shares. The Board of Directors of Galleon will determine the actual timing, payment and amount of dividends, if any, that may be paid by Galleon from time to time based upon, among other things, the cash flow, results of operations and financial conditions of

Galleon, the needs for funds to finance ongoing operations and other business considerations as the Board of Directors of Galleon considers relevant. Payment of dividends is subject to the consent of the Corporation's lenders.

DESCRIPTION OF CAPITAL STRUCTURE

The Corporation is authorized to issue an unlimited number of Class A Shares, an unlimited number of Class B Shares and an unlimited number of preferred shares, issuable in series. The following is a description of the rights, privileges, restrictions and conditions attaching to the share capital of the Corporation.

Class A Shares

The Corporation has an unlimited number of Class A Shares authorized. The holders of Class A Shares are entitled to: dividends if, as and when declared by the board of directors pro-rata with the Class B Shares; to one vote per share at any meeting of the shareholders of the Corporation; and upon liquidation to receive, pro-rata with the Class B Shares, all assets of the Corporation as are distributable to the holders of shares.

Class B Shares

The Corporation also has an unlimited number of Class B Shares authorized. The holders of Class B Shares are entitled to one vote per share at any meeting of the shareholders of the Corporation. The holders of Class B Shares are entitled to dividends, if, as and when declared by the Board of Directors, pro rata with the Class A Shares, and upon liquidation to receive, pro rata with the Class A Shares, all assets of the Corporation as are distributable to the holders of shares.

The Class B Shares are convertible, at the option of the Corporation, at any time after December 31, 2006 and before the close of business on December 31, 2008 into Class A Shares upon five days prior notice to holders of Class B Shares. The number of Class A Shares obtained upon conversion of each Class B Share will be equal to $10.00 divided by the greater of $1.00 and the "Current Market Price" of the Class A Shares (as defined in the share provisions) at the effective date of conversion.

If the Corporation fails to exercise the option to convert the Class B Shares into Class A Shares by the close of business on December 31, 2008, then the Class B Shares shall be convertible, at the option of the shareholder, at any time after January 1, 2009 and before February 1, 2009, into Class A Shares. The number of Class A Shares obtained upon conversion of each Class B Share will be equal to $10.00 divided by the greater of $1.00 and the Current Market Price of the Class A Shares at the effective date of conversion. Any Class B Shares outstanding at the close of business on February 1, 2009 shall be automatically converted into Class A Shares. The number of Class A Shares obtained upon conversion of each Class B Share will be equal to $10.00 divided by the greater of $1.00 and the Current Market Price of the Class A Shares at the effective date of conversion.

The conversion option may be exercised by shareholders by notice in writing given to the transfer agent of the Corporation accompanied by the share certificate or certificates representing the Class B Shares in respect of which the holder desires to exercise such conversion privilege.

Preferred Shares

Galleon is authorized to issue an unlimited number of preferred shares issuable in series, each series consisting of such number of shares and having such rights, privileges, restrictions and conditions as may be determined by the board of directors of Galleon prior to the issuance thereof. With respect to the payment of dividends and the distribution of assets in the event of liquidation, dissolution or winding up of Galleon, whether voluntary or involuntary, the preferred shares are entitled to preference over the Class A Shares and the Class B Shares and any other shares ranking junior to the preferred shares from time to time and may also be given such other preferences over the Class A Shares and Class B Shares and any other shares ranking junior to the preferred shares as may be determined at the time of creation of such series. At the date hereof, no series of preferred shares has been created.

MARKET FOR SECURITIES

The Class A Shares and Class B Shares are listed and posted for trading on the TSX under the symbols "GO.A" and "GO.B", respectively.

The following sets forth the price range and trading volume of the Class A Shares and Class B Shares on (as reported by such exchange) for the periods indicated.

	Class A Shares			Class B Shares		
	Price Range			Price Range		
	High ($/share)	Low ($/share)	Volume (000s)	High ($/share)	Low ($/share)	Volume (000s)
2007						
January	18.25	14.25	7,458,110	8.50	8.50	22,250
February	17.76	15.77	6,373,250	8.55	8.50	8,500
March	17.27	14.46	9,179,257	8.98	8.52	7,250
April	17.73	16.03	4,649,126	8.93	8.50	18,000
May	18.35	16.11	8,478,020	8.80	8.50	10,150
June	18.09	16.80	9,560,622	8.85	8.55	32,425
July	17.57	15.71	8,174,823	8.75	8.65	2,050
August	17.00	15.06	4,558,766	8.91	8.65	10,245
September	17.00	15.23	3,588,614	-	-	-
October	16.50	13.52	8,292,492	8.81	8.75	4,000
November	14.92	12.98	7,366,041	9.03	8.90	3,300
December	15.65	13.92	3,376,912	9.10	8.90	9,250
2008						
January	16.11	11.49	5,164,395	9.10	8.95	36,100
February	17.22	14.11	6,569,176	9.25	9.20	54,550
March 1-20	17.09	13.30	6,544,130	-	-	-

DIRECTORS AND OFFICERS

The names, municipalities of residence, positions with the Corporation, and principal occupation of the directors and officers of the Corporation are set out below and in the case of directors, the period each has served as a director of the Corporation.

Name and Municipality of Residence	Office Held	Principal Occupation	Director Since
Glenn R. Carley[(2)] Calgary, Alberta, Canada	Executive Chairman and Director	Executive Chairman of the Corporation and Executive Chairman of Flagship Energy Inc.	March 27, 2003
Steve Sugianto Calgary, Alberta, Canada	President, Chief Executive Officer and Director	President and Chief Executive Officer of the Corporation	May 16, 2003
John A. Brussa[(2)(3)(4)] Calgary, Alberta, Canada	Director	Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors)	May 16, 2003
Fred C. Coles[(1)(2)] Calgary, Alberta, Canada	Director	Executive Chairman, JOG Capital (private investment company)	May 16, 2003
William L. Cooke[(1)(3)] Magna Bay, British Columbia, Canada	Director	Independent Businessman	May 16, 2003

Name and Municipality of Residence	Office Held	Principal Occupation	Director Since
Brad R. Munro[(1)(5)] Saskatoon, Saskatchewan, Canada	Director	President and Chief Executive Officer of Bittercreek Capital Corporation, (a private investment and advisory firm)	January 16, 2004
Shivon M. Crabtree Calgary, Alberta, Canada	Vice-President, Finance and Chief Financial Officer	Vice-President, Finance and Chief Financial Officer of the Corporation	N/A
Dale Orton Calgary, Alberta, Canada	Vice-President, Engineering	Vice-President, Engineering of the Corporation	N/A
Devin K. Sundstrom Calgary, Alberta, Canada	Vice-President, Production	Vice-President, Production of the Corporation	N/A
Marc A. Houle Calgary, Alberta, Canada	Vice-President, Exploration West	Vice-President, Exploration West of the Corporation	N/A
James D. Iverson Calgary, Alberta, Canada	Vice-President, Exploration East	Vice-President, Exploration East of the Corporation	N/A
Christopher F. Tibbles Calgary, Alberta, Canada	Vice-President, Land	Vice-President, Land of the Corporation	N/A
William Wee Calgary, Alberta, Canada	Vice-President, Corporate Development	Vice-President, Corporate Development of the Corporation	N/A
C. Steven Cohen Calgary, Alberta, Canada	Secretary	Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors)	N/A

Notes:

(1) Member of the Audit and Reserves Committee.

(2) Member of the Compensation Committee.

(3) Member of the Corporate Governance Committee.

(4) Mr. Brussa was a director of Imperial Metals Limited, a corporation engaged in both oil and gas and mining operations, in the year prior to that corporation implementing a plan of arrangement under the *Company Act* (British Columbia) and under the *Companies' Creditors Arrangement Act* (Canada) which resulted in the separation of its two businesses. The reorganization resulted in the creation of two public corporations, Imperial Metals Corporation and IEI Energy Inc. (now Rider Resources Ltd.), both of whom trade on the Toronto Stock Exchange.

(5) Mr. Munro was a director of Kipp & Zonen Inc. ("Kipp & Zonen"), as part of his employment with GrowthWorks Canadian Fund Inc. ("Growthworks") from December 1996 to April 19, 2004. GrowthWorks held a convertible debenture in the principal amount of $2,000,000 which was originally funded in December 1996 with a maturity in March 2001. On March 25, 2004, Kipp & Zonen was served with Notice of Petition for Receiving Order by its landlord for unpaid rent. GrowthWorks served notice to Kipp & Zonen on April 7, 2004 with a Notice of Intention to Enforce Security under the *Bankruptcy and Insolvency Act* (Canada) under the terms of its amended and restated convertible debenture dated March 31, 2002. On April 21, 2004, GrowthWorks obtained an order of the Saskatchewan Court of Queen's Bench appointing Ernst & Young Inc. receiver of all of the undertaking, property and assets of the company. Effective April 19, 2004, Mr. Munro and the other directors and officers of Kipp & Zonen resigned.

(6) Galleon does not have an executive committee of its board of directors.

All of the above directors have held their principal occupations or other positions with the same organization as listed above for at least the last five years except as described under "Management" and "Audit and Reserves Committee Information – Composition of the Audit and Reserves Committee".

The term of office of each director expires at the next annual meeting of shareholders of the Corporation.

As at March 20, 2008, the directors and executive officers of Galleon, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, 4,630,251 Class A Shares and 25,790 Class B Shares or approximately 6.8% of the issued and outstanding Class A Shares and 2.8% of the outstanding Class B Shares.

MANAGEMENT

Glenn R. Carley, Executive Chairman

Mr. Carley has been involved in the oil and natural gas business for the past 30 years. Mr. Carley was the Chairman and Chief Executive Officer of the Corporation from March 27, 2003 to March 17, 2005. On March 17, 2005, Mr. Carley was appointed Executive Chairman. Mr. Carley is currently Executive Chairman and a director of Flagship Energy Inc., a junior oil and gas company listed on the TSX Venture Exchange. Mr. Carley has been a director of Culane Energy Corp., a public oil and gas company since December 2002. Mr. Carley is a director of Painted Pony Petroleum Ltd., a public oil and gas company since April 3, 2007. He is currently President of Selinger Capital Inc., a private investment company. He was a director of High Point Resources Inc., a public oil and gas company, from October 2001 to August, 2005. Mr. Carley was a director of Deep Resources Ltd., a public oil and gas company from December 2002 to June 2005. He was Chairman and CEO of Venture Energy. Inc., a private oil and gas company from December 2002 to January 2005.

Mr. Carley was co-founder, Chairman and Chief Executive Officer of Magin Energy Inc. a public oil and gas exploration and production company which was listed for trading on the Toronto Stock Exchange and was sold in June of 2001. Magin was a TSE 300 company prior to its sale. From 1988 to 1994 Mr. Carley was Vice-President and Secretary of Wascana Energy Inc., a public oil and gas exploration and production company based in Regina, Saskatchewan and trading on the Toronto Stock Exchange and the Montreal Exchange. Prior to his position with Wascana, Mr. Carley was General Counsel and Secretary of Mark Resources Inc. the successor to Precambrian Shield Resources Limited from 1987 to 1988 and General Counsel and Secretary of Canadian Roxy Petroleum Ltd. from 1981 to 1987.

Mr. Carley holds a Master of Business Administration Degree, a Bachelor of Laws degree and a Bachelor of Arts degree, all from the University of Saskatchewan.

Steve Sugianto, President and Chief Executive Officer, Director

Mr. Sugianto has been involved in the oil and natural gas business for the past 23 years. Mr. Sugianto was the Vice President, Engineering and Corporate Development of KeyWest Energy Corporation, a public oil and gas company that was listed on the TSX which reached 8,800 BOE/day of production and was sold in 2003. Prior thereto, Mr. Sugianto held positions of increasing responsibility at Remington Energy Ltd., HCO Energy Ltd., DeKalb Energy Canada Ltd., Wascana Energy Inc. and Esso/Imperial Oil Ltd.

Mr. Sugianto is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta. Mr. Sugianto holds a Bachelor of Science degree in Chemical and Petroleum Engineering from the University of Calgary and a Masters degree in Chemical and Petroleum Engineering from the University of Calgary.

Shivon M. Crabtree, Vice-President, Finance and Chief Financial Officer

Ms. Crabtree has been involved in the oil and natural gas business for the past 27 years. Ms. Crabtree was Vice President, Finance of Culane Energy Corp. from December 2002 to August 2007. Prior thereto, Ms. Crabtree was the Vice-President, Finance and Chief Financial Officer at High Point Resources Inc. from December 2001 to March 2004. She was Vice-President Finance and Chief Financial Officer of Venture Energy Inc. from December 2002 to January 2005. Ms. Crabtree was the Vice-President Finance and Chief Financial Officer at Magin Energy Inc. from June 1996 to June 2001. Ms. Crabtree held various positions at Wascana during the period 1981 to 1996.

Ms. Crabtree holds a Bachelor of Business Administration from the University of Regina and the Certified Management Accountant (CMA) designation.

Dale Orton, Vice-President, Engineering

Mr. Orton is a professional engineer with 14 years of exploitation, production, operations, business development and acquisition experience. Prior to being employed with the corporation, he held positions of increasing responsibility with Flowing Energy Corporation, KeyWest Energy Corporation, Velvet Exploration Ltd. and Renaissance Energy Ltd.

Mr. Orton holds a Bachelor of Engineering degree from the University of Victoria and is a Registered Professional Engineer in the province of Alberta.

Devin K. Sundstrom, Vice-President, Production

Mr. Sundstrom is a professional engineer with 14 years of drilling and completion, exploitation, production operations and acquisition experience. Prior to joining Galleon, he has held positions with increasing responsibility at Hunt Oil Company, Renaissance Energy Ltd. and Northstar Energy Corporation.

Mr. Sundstrom holds a Bachelor of Science Degree in Chemical and Petroleum Engineering from the University of Calgary and is a Registered Professional Engineer in the Province of Alberta.

Marc A. Houle, Vice-President, Exploration West

Mr. Houle has 13 years of diversified industry experience in Western Canada primarily focused in the Peace River Arch area where he has a strong history of finding oil and gas pools.

Mr. Houle holds a Bachelor of Science degree with Specialization in Geophysics from the University of Alberta.

James D. Iverson, Vice-President, Exploration East

Mr. Iverson is a professional geologist with 27 years of diversified industry experience in Western Canada. Mr. Iverson has a proven track record of discovering oil and gas pools mainly in the Peace River Arch and Central Alberta areas. He has held position of increasing responsibility at Baytex Energy Ltd., Hadrian Energy Corp., Wascana Energy Inc., Alberta Energy Oil and Gas Company Ltd., and Chieftain Development Company Ltd.

Mr. Iverson holds a Bachelor of Science degree with Honors in Geology from the University of Alberta and is registered as a Professional Geologist in Alberta.

Christopher F. Tibbles, Vice-President, Land

Mr. Tibbles is a landman with 11 years of experience in the oil and gas industry. His most recent position was Land Lead with EnCana Corp. ("EnCana") where he had an integral role in establishing south west Saskatchewan as a key area of growth for EnCana. Prior to EnCana, Mr. Tibbles was a Senior Landman with Pan Canadian Petroleum.

Mr. Tibbles holds a Bachelor of Commerce degree from the University of Calgary with a major in Petroleum Land Management. He is also an active member of the Canadian Association of Petroleum Landmen.

William Wee, Vice-President, Corporate Development

Mr. Wee is a professional engineer with 25 years of oil and gas experience in reservoir, exploration, and production engineering, drilling, completions, field operations, joint ventures, marketing and acquisitions. Prior to joining Galleon, Mr. Wee was the Vice President Engineering for Temple Engineering Inc., a private oil and gas exploration company, He has also held managerial and technical positions for Rio Alto Exploration, Ulster Petroleums, Wascana Energy, Husky Oil and Koch Exploration.

Mr. Wee holds Bachelor of Science in Chemical Engineering and Master of Engineering in Petroleum Engineering degrees from the University of Calgary. He is a Registered Professional Engineer in Alberta.

AUDIT AND RESERVES COMMITTEE INFORMATION

Audit and Reserves Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Audit and Reserves Committee of the board of directors is attached hereto as Schedule "C".

Composition of the Audit and Reserves Committee

The members of the Audit and Reserves Committee are William L. Cooke, Fred C. Coles and Brad R. Munro. The members of the Audit and Reserves Committee are independent (in accordance with National Instrument 52-110) and are financially literate. The following is a description of the education and experience of each member of the Audit and Reserves Committee.

Mr. William L. Cooke, Chairman

Mr. Cooke is the former President and Chief Executive Officer of MD Private Trust Company and MD Private Investment Management Inc, which are wholly-owned subsidiaries of the Canadian Medical Association. Prior to this, Mr. Cooke was an executive with Royal Bank and Royal Trust companies. He started his career in the Saskatchewan government and served in Finance, a crown corporation and various program delivery areas. He has a Master of Business Administration from the University of Saskatchewan. He is a director and chair of the audit committee of Hanwei Energy Services (HE:TSX) and of Okanagan University College. He is a director of Coast Capital Savings. He was a director of several private companies including MD Management and Lancet Investment Management Inc. He also served on the boards of the Canadian Medical Foundation, the advisory board of Vancouver College, and the boards of not-for-profit organizations.

He has been a director and chair of the Galleon audit committee since the creation of the Company in 2003. Prior to Galleon, he was a director and chair of the audit committee for Magin Energy Inc from 1994 to 2001. He has completed the Canadian Securities Course, the Partners, Directors and Officers qualifying exam, and the Directors Education Program under the Institute of Corporate Directors (under which he successfully completed the ICD's accreditation requirements for the ICD.D designation). .

Mr. Fred C. Coles

Mr. Coles is a professional engineer with over 40 years of experience in the oil and gas industry. He is the Executive Chairman of JOG Capital, a private investment company. Prior thereto, Mr. Coles was the Executive Chairman of Applied Terravision Systems Inc., a computer software development company, from 1994 to March 2002. Prior to 1994, Mr. Coles provided independent petroleum consulting to domestic and international clients for 21 years during his employment at Coles Gilbert Associates Ltd. (now GLJ Petroleum Consultants Ltd. Associates Ltd.) as Chairman and President. Mr. Coles gained petroleum operating company experience during the period of 1964 – 1973 with Hudson's Bay Oil and Gas Company, Aquitane Company of Canada Ltd. and Pennant Puma Oils Ltd. Mr. Coles earned a Bachelor of Science in Petroleum Engineering with Honours from the University of Wyoming in 1969. Mr. Coles is also a director of a number of private and public companies.

Mr. Coles is a registered Professional Engineer in the province of Alberta and is also a member of the Petroleum Society of the Canadian Institute of Mining, Metallurgy and Petroleum.

Mr. Brad R. Munro

Mr. Munro is the President and Chief Executive Officer of Bittercreek Capital Corporation, a private investment and advisory firm and, through Bittercreek Capital Corporation, has been a contractor to Growthworks Capital WV Ltd. and its affiliates in the role of Vice President, Investments since May 2006. Prior thereto, Mr. Munro was an employee of GrowthWorks Capital Ltd. and its affiliates since September 1991. Mr. Munro holds a Bachelor of Commerce degree from the University of Saskatchewan and has extensive experience in corporate finance and investment in the oil and gas and other industries. Mr. Munro presently serves as a director of five private companies and five public companies including Bonnett's Energy Services Trust which is listed on the TSX and Fairmount Energy Inc, 49 North Resource Fund and Flagship Energy Inc. which are listed on the TSX Venture Exchange. Mr. Munro was the lead director of the independent committee on the recent privatization of CCS Income Trust.

Pre-Approval of Policies and Procedures

The Audit and Reserves Committee has adopted a policy to review and pre-approve any non-audit services to be provided to Galleon by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member report to the Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Committee from time to time.

External Auditor Service Fees

Audit Fees

The aggregate fees billed by the Corporation's external auditor in each of the last two fiscal years for audit services were $204,500 in 2007 and $165,000 in 2006.

Audit-Related Fees

The aggregate fees billed in each of the last two fiscal years for assurance and related services by the Corporation's external auditor that are reasonably related to the performance of the audit or review of the Corporation's financial statements that are not reported under "Audit Fees" above were $73,500 in 2007 and $89,500 in 2006. Fees were billed for audit related services including the audit of financial statements for properties acquired, review of pro-forma financial statements, services rendered in connection with financings, and meetings and discussions related to the Corporation's internal control documentation.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by the Corporation's external auditor for tax compliance, tax advice and tax planning were $12,450 in 2007 and $9,000 in 2006. Fees were billed for services provided in the preparation of corporate tax returns.

All Other Fees

The aggregate fees billed in each of the last two fiscal years for other services by the Corporation's external auditor for other services were $18,000 in 2007 and nil in 2006. Fees were billed for translation services provided.

CONFLICTS OF INTEREST

The directors or officers of the Corporation may also be directors or officers of other oil and gas companies or otherwise involved in natural resource exploration and development and situations may arise where they are in a conflict of interest with the Corporation. Conflicts of interest, if any, which arise will be subject to and governed by procedures prescribed by the ABCA which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

HUMAN RESOURCES

As at December 31, 2007, Galleon employed 50 full-time employees located in the head office, and 8 part-time consultants. Galleon intends to add additional professional and administrative staff as the need arises.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Corporation are Ernst & Young LLP, Chartered Accountants, 1000, 444 – 2nd Avenue S.W., Calgary, Alberta, T2P 5E9.

Valiant Trust Company of Canada, at its principal offices in Calgary, Alberta and BNY Trust Company of Canada, at its principal offices in Toronto, Ontario, are the transfer agent and registrar of the Class A Shares and Class B Shares.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

To the knowledge of the Corporation, there are no legal proceedings material to the Corporation which the Corporation or any of its subsidiaries is, or was a party to, or that any of their respective property is or was the subject of, during the last completed financial year, nor are there any such proceedings known to the Corporation to be contemplated.

During the year ended December 31, 2007 there were: (i) no penalties or sanctions imposed against the Corporation or its subsidiaries or by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against the Corporation or its subsidiaries that would likely be considered important to a reasonable investor in making an investment decision, and (iii) no settlement agreements the Corporation or its subsidiaries entered into with a court relating to a securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors or executive officers of the Corporation, of any shareholder who beneficially owns or controls or directs, directly or indirectly, more than 10% of the outstanding voting securities of the Corporation, or any other Informed Person (as defined in National Instrument 51-102) or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect the Corporation or any of its subsidiaries except as follows.

Effective January 16, 2008, Galleon acquired all of the outstanding common shares of ExAlta on the basis of 0.118 Class A Shares in exchange for each outstanding common share of ExAlta. Fred C. Coles, a director of the Corporation was also a director of ExAlta and held 51,000 common shares of ExAlta and options to purchase 80,000 common shares of ExAlta.

Certain directors and officers of Galleon have participated in private placements and public offerings by Galleon on the same basis as other arm's length subscribers to such offerings.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, neither the Corporation nor any of its subsidiaries has entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year which are still in effect other than:

1. the underwriting agreement dated as of March 23, 2007 among Galleon and Sprott Securities Inc., Scotia Capital Inc., FirstEnergy Capital Corp., TD Securities Inc. and Maison Placements Canada Inc. in respect of the private placement of 1,481,500 Class A Shares issued on a "flow-through" basis (see "General Development of the Business – 2007");

2. the underwriting agreement made as of September 6, 2007 among Galleon and Cormark Securities Inc., FirstEnergy Capital Corp., Scotia Capital Inc., TD Securities Inc., HSBC Securities (Canada) Inc. and Maison Placements Canada Inc. in respect of the public offering of 1,869,200 Class A Shares and

1,463,400 Class A Shares issued on a "flow-through" basis (see "General Development of the Business – 2007"); and

3. Arrangement Agreement made as of November 24, 2007 among Galleon and ExAlta in respect of the arrangement pursuant to which the Corporation acquired all of the outstanding shares of ExAlta (see "Recent Developments").

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than DeGolyer, the Corporation's independent engineering evaluators, GLJ Petroleum Consultants Ltd. ("GLJ"), ExAlta's independent engineering evaluators, and Ernst & Young LLP, the Corporation's and ExAlta's auditors. None of the principals of DeGolyer had any registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of the Corporation's associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them. None of the principles of GLJ had any registered or beneficial interests, direct or indirect, in any securities or other property of ExAlta or the Corporation or of ExAlta's or the Corporation's associates or affiliates either at the time they prepared the statement, report or evaluation prepared by it, at any time thereafter or to be received by them. Ernst & Young LLP are independent in accordance with the auditor's rules of professional conduct of the Institute of Chartered Accountants of Alberta.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta, British Columbia, and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the Corporation's operations in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing - Oil and Natural Gas

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to the markets, the value of refined products, the supply/demand balance, and other contractual terms. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

The governments of Alberta, British Columbia, and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

Pipeline Capacity

Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market natural gas production. In addition, the pro-rationing of capacity on the inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, United States of America, and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price subject to an exception with respect to certain voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import-price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur, and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery, and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to eliminate, amend or allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

The Canadian federal corporate income tax rate levied on taxable income is 22.1% effective January 1, 2007 for active business income including resource income. With the elimination of the corporate surtax effective January 1, 2008 and other rate reductions introduced in the October 2007 Economic Statement and Notice of Ways and Means Motion, 2006 Federal Budget, the federal corporate income tax rate will decrease to 15% in five steps: 19.5% on January 1, 2008, 19% on January 1, 2009; 18% on January 1, 2010, 16.5% on January 1, 2011 and 15% on January 2012.

Alberta

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. Currently, the amount of royalties that are payable is influenced by the oil production, density of the oil, and the vintage of the oil. Originally, the vintage classified oil as "new oil" and "old oil" depending on when the oil pools were discovered. If the pool was discovered prior to March 31, 1974 it is considered "old oil", if it was discovered after March 31, 1974 and before September 1, 1992, it is considered "new oil". The Alberta government introduced in 1992 a Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 1, 1992. The new oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 35%.

The royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is between 15% and 30%, in the case of new natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price. Natural gas produced from qualifying intervals in eligible gas wells spudded or deepened to a depth below 2,500 metres is also subject to a royalty exemption, the amount of which depends on the depth of the well.

Oil sands projects are subject to a specific regulation made effective July 1, 1997, and expiring June 30, 2009, which, among other things, determines the Crown's share of crude and processed oil sands products.

Regulations made pursuant to the Mines and Minerals Act (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program ("ARTC") was to be eliminated, effective January 1, 2007. The programs affected by this announcement are: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re-Entry Royalty Reduction. The program being introduced is the Innovative Energy Technologies Program (the "IETP") which is intended to promote the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy will be the one to decide which projects qualify and the level of support that will be provided. The deadline for the IETP's third round of applications was May 31, 2007. The successful applicants have not yet been announced and it appears, based on the previous two rounds, that the selection process can take at least 8 months.] The technical information gathered from this program is to be made public once a two-year confidentiality period expires.

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" (the "**NRF**") containing the government's proposals for Alberta's new royalty regime that is scheduled to be effective on January 1, 2009. The proposed NRF includes new royalty formulas for conventional oil and natural gas that will operate on sliding scales that are determined by commodity prices and well productivity; in addition to the policy of "shallow rights reversion". The Alberta government is intending to implement this policy in order to maximize the development of currently undeveloped resources which is consistent with the government's objective of maximizing recovery of known gas resources, while increasing royalty revenues. The policy's objective is for the mineral rights to shallow gas geological formations that are not being developed to revert back to the government and be made available for resale. It appears that leaseholders will get a grace period before the shallower zones are reverted to the Crown, which is still to be determined. Substantial legislative, regulatory and systems updates will be introduced before changes become fully effective in January 2009. See "*Risk Factors – New Alberta Royalty Regime*".

British Columbia

Producers of oil and natural gas in the Province of British Columbia are required to pay annual rental payments with respect to the Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands. The amount payable as a royalty in respect of oil depends on the type of oil, the value of the oil, the quantity of oil produced in a month, and the vintage of the oil. Generally, the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 (old oil), between October 31, 1975, and June 1, 1998 (new oil), or after June 1, 1998 (third-tier oil). The royalty rates are calculated in three stages, which take into account the vintage of the oil, if the oil produced has already been sold and any royalty exempt value applicable (exempt wells). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production or 11,450m^3 produced, whichever comes first; and the royalties for third-tier oil are the lowest reflecting the higher costs of exploration and extraction that the producers would incur. The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the price obtained by the producer, and a prescribed minimum price. However, when the reference price is below the select price (a parameter used in the royalty rate formula), the royalty rate is fixed. As an incentive for the production and marketing of natural gas, which may have been flared, natural gas produced in association with oil has a lower royalty then the royalty payable on non-conservation gas.

On May 30, 2003, the Ministry of Energy and Mines for the Province of British Columbia announced an Oil and Gas Development Strategy for the Heartlands ("Strategy"). The Strategy is a comprehensive program to address road infrastructure, targeted royalties and regulatory reduction, and British Columbia service sector opportunities. In addition, the Strategy will result in economic and employment opportunities for communities in British Columbia's heartlands.

Some of the financial incentives in the Strategy include:

Royalty credits of up to $30 million annually towards the construction, upgrading, and maintenance of road infrastructure in support of resource exploration and development. Funding will be contingent upon an equal contribution from industry.

Changes to provincial royalties: new royalty rates for low productivity natural gas to enhance marginally economic resources plays, royalty credits for deep gas exploration to locate new sources of natural gas, and royalty credits for summer drilling to expand the drilling season.

Saskatchewan

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month, and the value of the oil. For Crown royalty and freehold production tax purposes, crude oil is considered "heavy oil", "southwest designated oil", or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil" introduced October 1, 2002, "third tier oil", "new oil", or "old oil") of oil production are applicable to each of the three crude oil types. The Crown royalty and freehold production tax structure for crude oil is price sensitive and varies between the base royalty rates of 5% for all "fourth tier oil" to 20% for "old oil". Marginal royalty rates are 30% for all "fourth tier oil" to 45% for "old oil".

The amount payable as a royalty in respect of natural gas is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. The royalty and production tax classifications of gas production are "fourth tier gas" introduced October 1, 2002, "third tier gas", "new gas", and "old gas". The Crown royalty and freehold production tax for gas is price sensitive and varies between the base royalty rate of 5% for "fourth tier gas" and 20% for "old gas". The marginal royalty rates are between 30% for "fourth tier gas" and 45% for "old gas".

On October 1, 2002, the following changes were made to the royalty and tax regime in Saskatchewan:

- A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale and is produced from: (a) oil wells with a finished drilling date on or after October 1, 2002, and (b) oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 cubic metres of gas for every cubic metre of oil. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65 thousand cubic metres in a month. The associated natural gas royalty/tax regime will apply to gas produced from oil wells affected by concurrent production approvals after October 1, 2002 if the oil wells meet (a) or (b) above.

- A modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from oil wells and gas wells with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of zero per cent.

- The elimination of the re entry and short section horizontal oil well royalty/tax categories. All horizontal oil wells with a finished drilling date on or after October 1, 2002, will receive the "fourth tier" royalty/tax rates and new incentive volumes.

- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a non-deep oil well qualifies for a 6,000 cubic metre incentive volume.

- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a deep oil well qualifies for a 16,000 cubic metre incentive volume.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("**RTR**") as a response to the federal government disallowing crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to seven years since the federal government had the initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan's RTR will be wound down as a result of the federal government's plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

In June 19, 2007, the Government of Saskatchewan introduced the Orphan Well and Facility Liability Management Program pursuant to the amendment of the *Oil and Gas Conservation Act* and the *Oil and Gas Conservation Regulations*, 1985. The program includes a security deposit, which has two purposes: (i) preventing the individual with insufficient financial capability from acquiring oil and gas wells or facilities; and (ii) in the case of a bankrupt company, the funds cover for the decommissioning and reclaiming of orphan property. An additional change introduced is the mandatory licensing of all upstream oil and gas facilities in Saskatchewan.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms from two years, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the *Climate Change and Emissions Management Amendment Act* came into effect on July 1, 2007. Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or (iii) by contributing to the Climate Change and Emissions Management Fund. Industries can either choose one of these options or a combination thereof. The Corporation will be committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment, and will be taking such steps as required to ensure compliance with the EPEA and similar legislation in other jurisdictions in which it operates. The Corporation believes that it is in material compliance with applicable environmental laws and regulations. The Corporation also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

In January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for *in situ* oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating CO_2 from other emissions supporting carbon capture and storage.

British Columbia's Environmental Assessment Act became effective June 30, 1995. This legislation rolls the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental review process. On February 27, 2007 the Government of British Columbia unveiled the Energy Plan outlining the Province's strategy towards the environment and which includes targeting for zero net greenhouse gas emissions, promoting new investments in innovation, and becoming the world's leader in sustainable environmental management. For this purpose, on December 18, 2007 proposals were sought for applications to the Innovative Clean Energy Fund, in order to attract new technologies that will help solve energy and environmental issues. With regards to the oil and gas industry the objective is to achieve clean energy through conservation and energy efficient practices, whilst competitiveness is advocated in order to attract investment for the development of the oil and gas sector. Among the changes to be implemented are: (i) a new of Net Profit Royalty Program; (ii) the creation of a Petroleum Registry; (iii) the establishment of an infrastructure royalty program (combining roads and pipelines); (iv) the elimination of routine flaring at producing wells; (v) the creation of policies and measures for the reduction of emissions; (vi) the development of unconventional resources such as tight gas and coalbed gas; and (vii) new the Oil and Gas Technology Transfer Incentive Program that encourages the research, development and use of innovative technologies to increase recoveries from existing reserves and promotes responsible development of new oil and gas reserves. Furthering these initiatives, on February 19, 2008 the provincial Government announced that starting on July 1, 2008, provided the legislation is approved; a revenue-neutral carbon tax will be applied to all fossil fuels used in the Province. The tax would be phased in, and the initial rate would be based on CO2e of $10 per tonne for the first six months of 2009 and $15 per tonne for the last six months of 2009, following $5 per tonne increases on July of every year until 2012. Tax credits and reductions will be used in order to offset the tax revenues that the Government would receive otherwise.

In December, 2002, the Government of Canada ratified the Kyoto Protocol ("**Protocol**"). The Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business-as-usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. It is questionable, based on the Updated Action Plan announced by the federal government (see below), that the Kyoto target of 6% below 1990 emission levels will be enforced in Canada. Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the Kyoto Protocol, was passed by the House of Commons on February 14, 2007. On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "**Action Plan**") also known as ecoACTION which includes the regulatory framework for air emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products.

The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and targeting research to lower the cost of technology.

In order to strengthen the Action Plan, on March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the "**Updated Action Plan**") which provides some additional guidance with respect to the Government's plan to reduce greenhouse gas emissions by 20% by 2020 and by 60% to 70% by 2050.

The Updated Action Plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and gas and refining. The Updated Action Plan is intended to create a carbon emissions trading market, including an offset system, to provide incentive to reduce greenhouse gas emission and establish a market price for carbon. There are mandatory reductions of 18% from the 2006 baseline starting in 2010 and an additional 2% in subsequent years for existing facilities. This target will be applied to regulated sectors on a facility-specific, sector-wide or corporate basis; in the case of oils sands production, petroleum refining, natural gas pipelines and upstream oil and gas the target will be considered facility-specific (sectors in which the facilities are complex and diverse, or where emissions are affected by factors beyond the control of the facility operator). Emissions from new facilities, which are those built between 2004 and 2011, will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time, and will be granted a 3-year grace period during which no emissions intensity targets will apply. Targets will begin to apply on the fourth year of commercial operation and the baseline will be the third year's emissions intensity, with a 2% continuous annual emission intensity improvement required. The definition of new facility also includes greenfield facilities, major expansions constituting more than a 25% increase in a facility's physical capacity, as well as transformations to a facility that involve significant changes to its processes. For upstream oil and gas and natural gas pipelines, it will be applied using a sector-specific approach. For the oil sands, its application will be process-specific, oil sands plants built in 2012 and later, those which use heavier hydrocarbons, up-graders and *in-situ* production will have mandatory standards in 2018 that will be based on carbon capture and storage.

In the following regulated sectors, the Updated Action Plan will apply only to facilities exceeding a minimum annual emissions threshold: (i) 50,000 tonnes of CO_2 equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalent per upstream oil and gas facilities; and (iii) 10,000 boe/d/company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of CO_2 equivalent per year per facility.

Four separate compliance mechanisms are provided in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. The most significant of these compliance mechanisms, at least initially, will be the Technology Fund and for which regulated entities will be able to contribute in order to comply with emissions intensity reductions. The contribution rate will increase over time, beginning at $15 per tonne for the 2010-12 period, rising to $20 per tonne in 2013, and thereafter increasing at the nominal rate of GDP growth. Contribution limits will correspondingly decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as mentioned above.

The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either cancel the offset credits or bank them for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

Finally, a one-time credit of up to 15 Mt worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict either the nature of those requirements or the impact on the Corporation and its operations and financial condition at this time.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs that could have a material adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks could have a material adverse effect on the Corporation.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's oil and gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

Project Risks

The Corporation will manage a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas will depend upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States and Canada, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Corporation's carrying value of its proved reserves, borrowing capacity, revenues, profitability and cash flows from operations.

Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Corporation may, in part, be determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could reduce the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation which could require that a portion, or all, of the Corporation's bank debt be repaid.

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore effected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Such material increases in the value of the Canadian dollar have negatively impacted Fairborne's operating entities production revenues. Further material increases in the value of the Canadian dollar would exacerbate this negative impact. This increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates could accordingly impact the future value of the Corporation's reserves as determined by independent evaluators.

To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Corporation may contract.

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, which could negatively impact the market price of the Corporation Shares.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle-East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Corporation's net production revenue.

In addition, the Corporation's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on the Corporation. The Corporation will not have insurance to protect against the risk from terrorism.

Competition

The petroleum industry is competitive in all its phases. The Corporation will compete with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Corporation's competitors will include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. As a result, the Corporation will have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others will therefore depend upon a number of factors that may be outside of the Corporation's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Corporation's costs, any of which may have a material adverse effect on the Corporation's intended business, financial condition and results of operations. In order to conduct oil and gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

New Alberta Royalty Regime

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" containing the government's proposals for Alberta's new royalty regime which is scheduled to be effective on January 1, 2009. Given that the NRF has only recently been announced, it is not possible at this time to determine the full impact of the NRF on the Corporation's financial condition and operations.

The Corporation cannot provide any assurance that the NRF will be implemented in the form proposed. If changes are made to the NRF before it is implemented by the Alberta government, such changes could result in the implementation of a new royalty regime that impacts the Corporation in a materially different manner, and that is more adverse to the Corporation, than the NRF as currently proposed.

Kyoto Protocol

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and will subject the Corporation to comply with the new regulatory framework announced on March 10, 2008 by the Federal Government which is intended to force large industries to reduce emissions of greenhouse gases, in addition to the government of Canada's proposed *Clean Air Act* of 2006 and Alberta's recently enacted *Climate Change and Emissions Management Act*. The direct or indirect costs of these regulations may adversely affect the expected business of the Corporation. See "*Industry Conditions – Environmental Regulation*".

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. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation 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. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Corporation's financial condition, results of operations or prospects. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Kyoto Protocol or as otherwise determined, 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 the impact on the Corporation and its operations and financial condition. See "Industry Conditions – Environmental Regulation".

Management of Growth

The Corporation may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this growth could have a material adverse impact on its business, operations and prospects.

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse affect on the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

Substantial 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. If the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. 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 financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Corporation.

Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time, could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Dilution

The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Corporation which may be dilutive.

Hedging

From time to time the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities. To the extent the Corporation is not the operator of its oil and gas properties, the Corporation will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which could result in a reduction of the revenue received by the Corporation.

Expiration of Licences and Leases

The Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's results of operations and business.

Insurance

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on the Corporation.

Dividends

The Corporation has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other business considerations as the board of directors of the Corporation considers relevant.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Corporation is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful this could have an adverse effect on the Corporation and its operations.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation.

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures could have a material adverse effect on the Corporation and its cash flow from operations. 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.

Conflicts of Interest

Certain directors of the Corporation are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "*Directors and Officers*" and "*Conflicts of Interest*".

ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans is contained in the Corporation's information circular for the Corporation's most recent annual meeting of securityholders that involved the election of directors. Additional financial information is contained in the Corporation's consolidated financial statements and the related management's discussion and analysis for the Corporation's most recently completed financial year.

SCHEDULE "A"
FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Galleon Energy Inc. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the board of directors of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of Form 51-102F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that the reserves are categorized according to the probability of their recovery.

DATED as of this 27th day of March, 2008.

(signed) "*Steve Sugianto*"
Steve Sugianto
President and Chief Executive Officer

(signed) "*Shivon M. Crabtree*"
Shivon M. Crabtree
Vice-President, Finance and Chief Financial Officer

(signed) "*Fred C. Coles*"
Fred C. Coles
Director

(signed) "*William L. Cooke*"
William L. Cooke
Director

SCHEDULE "B"
FORM 51-101F2
REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATORS

To the board of directors of Galleon Energy Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2007. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2007, and identifies the respective portions thereof that we have evaluated on to the Company's board of directors:

Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (before income tax, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
			M$	M$	M$	M$
DeGolyer and MacNaughton Canada Limited	Appraisal Report as of December 31, 2007 on Certain Properties owned by Galleon Energy Inc. dated March 12, 2008	Canada	-	1,111,865	-	1,111,865

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However any variation should be consistent with the fact that reserves are categorized according to the probability of their recovery.

EXECUTED as to our report referred to above.

DeGolyer and MacNaughton Canada Limited, Calgary, Alberta, dated March 12, 2008.

DeGolyer and MacNaughton Canada Limited

Per: (signed) *"Colin P. Outtrim"*
Colin P. Outtrim, P.Eng.

SCHEDULE "C"

AUDIT AND RESERVES COMMITTEE
MANDATE AND TERMS OF REFERENCE

Role and Objective

The Audit and Reserves Committee (the "Committee") is a committee of the board of directors (the "Board") of Galleon Energy Inc. ("Galleon" or the "Corporation") to which the Board has delegated its responsibility for (i) the oversight of the nature and scope of the annual audit, the oversight of management's reporting on internal accounting standards and practices, the review of financial information, accounting systems and procedures, financial reporting and financial statements and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information; and (ii) the matters set forth herein in respect of certain responsibilities of the Board in accordance with National Instrument 51-101 ("NI 51-101").

The primary objectives of the Committee are as follows:

1. To assist directors in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Galleon and related matters;
2. To provide better communication between directors and external auditors;
3. To enhance the external auditor's independence;
4. To increase the credibility and objectivity of financial reports;
5. To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors; and
6. To deal with such matters as provided herein in respect of NI 51-101.

Membership of Committee

1. The Committee will be comprised of at least three (3) directors of Galleon or such greater number as the Board may determine from time to time and: (i) all members of the Committee shall be "independent" (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("MI 52-110") unless the Board determines that the exemption contained in MI 52-110 is available and determines to rely thereon; and (ii) shall meet the requirements of Section 3.5 of NI 51-101.
2. The Board of Directors may from time to time designate one of the members of the Committee to be the Chair of the Committee.
3. All of the members of the Committee must be "financially literate" (as defined in MI 52-110) unless the Board determines that an exemption under MI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of MI 52-110.

Mandate and Responsibilities of Committee

Audit Matters

It is the responsibility of the Committee to:

1. Oversee the work of the external auditors, including the resolution of any disagreements between management and the external auditors regarding financial reporting.
2. Satisfy itself on behalf of the Board with respect to Galleon's internal control systems.

3. Review the annual and interim financial statements of Galleon and related management's discussion and analysis ("MD&A") prior to their submission to the Board for approval. The process should include but not be limited to:

   - reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;
   - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
   - reviewing accounting treatment of unusual or non-recurring transactions;
   - ascertaining compliance with covenants under loan agreements;
   - reviewing disclosure requirements for commitments and contingencies;
   - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
   - reviewing unresolved differences between management and the external auditors; and
   - obtain explanations of significant variances with comparative reporting periods.

4. Review the financial statements, prospectuses, MD&A, annual information forms ("AIF") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Galleon's disclosure of all other financial information and will periodically assess the accuracy of those procedures.

5. With respect to the appointment of external auditors by the Board:

   - recommend to the Board the external auditors to be nominated;
   - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;
   - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;
   - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
   - review and pre-approve any non-audit services to be provided to Galleon or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre–approve non–audit services, provided that the member(s) report to the Committee at the next scheduled meeting such pre–approval and the member(s) comply with such other procedures as may be established by the Committee from time to time.

6. Review with external auditors (and internal auditor if one is appointed by Galleon) their assessment of the internal controls of Galleon, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee will also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Galleon and its subsidiaries.

7. Review risk management policies and procedures of Galleon (i.e. hedging, litigation and insurance).

8. Establish a procedure for:

   - the receipt, retention and treatment of complaints received by Galleon regarding accounting, internal accounting controls or auditing matters; and

   - the confidential, anonymous submission by employees of Galleon of concerns regarding questionable accounting or auditing matters.

9. Review and approve Galleon's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of Galleon.

The Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Corporation. The Committee will also have the authority to investigate any financial activity of Galleon. All employees of Galleon are to cooperate as requested by the Committee.

The Committee may also retain persons having special expertise and/or obtain independent professional advise to assist in filling their responsibilities at such compensation as established by the Committee and at the expense of Galleon without any further approval of the Board.

Reserves Matters

The Committee is responsible for:

1. reviewing the Corporation's procedures relating to the disclosure of information with respect to oil and gas activities including reviewing its procedures for complying with its disclosure requirements and restrictions set forth under applicable securities requirements;

2. reviewing the Corporation's procedures for providing information to the independent evaluator;

3. meeting, as considered necessary, with management and the independent evaluator to determine whether any restrictions placed by management affect the ability of the evaluator to report without reservation on the Reserves Data (as defined in NI 51-101) (the "Reserves Data") and to review the Reserves Data and the report of the independent evaluator thereon (if such report is provided);

4. reviewing the appointment of the independent evaluator and, in the case of any proposed change to such independent evaluator, determining the reason therefor and whether there have been any disputes with management;

5. providing a recommendation to the Board of Directors as to whether to approve the content or filing of the statement of the Reserves Data and other information that may be prescribed by applicable securities requirements including any reports of the independent engineer and of management in connection therewith;

6. reviewing the Corporation's procedures for reporting other information associated with oil and gas producing activities; and

7. generally reviewing all matters relating to the preparation and public disclosure of estimates of the Corporation's reserves.

Meetings and Administrative Matters

1. At all meetings of the Committee every resolution shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall be entitled to a second or casting vote.

2. The Chair will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.

3. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board unless otherwise determined by the Committee or the Board.

4. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer will attend meetings of the Committee where matters relating to the functions as the Audit Committee are dealt with, unless otherwise excused from all or part of any such meeting by the Chairman.

5. The Committee will meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.

6. The Committee will meet with the independent evaluator at least once per year (in connection with the preparation and/or finalization of the year end reserves report) and at such other times as the independent evaluator and the Committee consider appropriate.

7. Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

8. The Committee may invite such officers, directors and employees of the Corporation as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.

9. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

10. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation.

11. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee, each member will hold such office until the Committee is reconstituted.

12. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chairman of the Board by the Committee Chair.

SCHEDULE "D"

EXALTA ENERGY INC.
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Reserves Data and Other Information

The Corporation acquired all of the outstanding common shares of ExAlta effective January 16, 2008, pursuant to a plan of arrangement under the ABCA (see "Recent Developments").

The Corporation engaged GLJ Petroleum Consultants Ltd. ("GLJ") to provide an evaluation of ExAlta's proved and proved plus probable reserves as at December 31, 2007. The reserves data set forth below (the "Reserves Data") is based upon the GLJ Report. The date of preparation of the GLJ Report is March 5, 2008. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of ExAlta and the net present values of future net revenue for these reserves using forecast prices and costs. The GLJ Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. **The Reserves Committee of the board of directors of the Corporation has reviewed and approved the GLJ Report.**

All of ExAlta's reserves are in Canada and, specifically, in the provinces of Alberta and British Columbia.

All evaluations of future net production revenue set forth in the tables below are based on forecast prices and costs and are after direct lifting costs, normal allocated overhead and future capital investments. It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of ExAlta's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2007
FORECAST PRICES AND COSTS

	RESERVES									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (MBOE)	Net (MBOE)
Proved Developed										
Producing	241	212	886	750	6,010	4,422	327	223	2,456	1,923
Non-Producing	7	5	60	50	969	730	3	2	232	178
Proved Undeveloped	0	0	828	650	410	342	7	5	904	712
Total Proved	249	217	1,775	1,450	7,390	5,494	336	230	3,591	2,813
Probable	157	140	822	693	3,617	2,792	125	86	1,707	1,384
Total Proved plus Probable	406	357	2,597	2,143	11,007	8,286	461	316	5,299	4,197

NET PRESENT VALUES OF FUTURE NET REVENUE

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year ($/BOE)
Proved Developed											
Producing	62	54	48	44	40	62	54	48	44	40	25.05
Non-Producing	5	4	4	3	3	5	4	4	3	3	21.03
Proved Undeveloped	28	19	14	10	8	27	19	13	10	8	19.24
Total Proved	94	77	66	58	51	93	77	65	57	51	23.33
Probable	54	32	22	17	14	40	24	17	13	11	16.05
Total Proved plus Probable	148	109	88	75	65	134	101	82	71	62	20.93

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2007 FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (MM$)	ROYALTIES (MM$)	OPERATING COSTS (MM$)	DEVELOPMENT COSTS (MM$)	WELL ABANDONMENT COSTS (MM$)	FUTURE NET REVENUE BEFORE INCOME TAXES (MM$)	INCOME TAXES (MM$)	FUTURE NET REVENUE AFTER INCOME TAXES (MM$)
Total Proved	195	38	54	7	2	94	1	93
Total Proved plus Probable	300	55	85	9	2	148	14	134

FUTURE NET REVENUE BY PRODUCTION GROUP AS OF DECEMBER 31, 2007 FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (MM$)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year ($/BOE) ($/Mcfe)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	9	$31.69/BOE
	Heavy Oil (including solution gas and other by-products)	42	$23.02/BOE
	Natural Gas (including by-products but excluding solution gas from oil wells)	14	$3.42/Mcfe
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	15	$27.11/BOE
	Heavy Oil (including solution gas and other by-products)	54	$20.29/BOE
	Natural Gas (including by-products but excluding solution gas from oil wells)	19	$3.19/Mcfe

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the GLJ Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

   Reserve Categories

   Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

   - analysis of drilling, geological, geophysical and engineering data;
   - the use of established technology; and
   - specified economic conditions, specifically the forecast prices and costs.

   Reserves are classified according to the degree of certainty associated with the estimates.

   (a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

   (b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

   Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

   Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

   (c) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

      (i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

      (ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

   (d) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

   In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserve estimates are prepared). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

3. Forecast Costs and Price Assumptions

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by GLJ in the GLJ Report were GLJ's forecasts, as at January 1, 2008, as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

	OIL							
Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Oil Price 40° API ($Cdn/Bbl)	Hardisty Heavy 12° API ($Cdn/Bbl)	Natural Gas Alberta Spot Gas Price ($Cdn/Mcf)	Pentanes Plus Edmonton ($Cdn/Bbl)	Butanes Price Edmonton ($Cdn/Bbl)	Inflation Rates[1] %/Year	Exchange Rate[2] ($US/$Cdn)
Forecast								
2008	92.00	91.10	54.02	6.53	92.92	72.88	2.0	1.0
2009	88.00	87.10	51.61	7.33	88.84	69.68	2.0	1.0
2010	84.00	83.10	49.19	7.37	84.76	66.48	2.0	1.0
2011	82.00	81.10	47.98	7.37	82.72	64.88	2.0	1.0
2012	82.00	81.10	47.98	7.37	82.72	64.88	2.0	1.0
2013	82.00	81.10	49.04	7.37	82.72	64.88	2.0	1.0
2014	82.00	81.10	50.09	7.57	82.72	64.88	2.0	1.0
2015	82.00	81.10	51.15	7.74	82.72	64.88	2.0	1.0
2016	82.02	81.12	52.21	7.91	82.74	64.89	2.0	1.0
2017	83.66	82.76	53.29	8.08	84.42	66.21	2.0	1.0
2018+	Escalated oil, gas and product prices at 2% per year thereafter							

Notes:

(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by ExAlta for the year ended December 31, 2007, were $6.21/Mcf for natural gas, $70.22/Bbl for light crude oil, $53.61/Bbl for heavy oil and $35.86/Bbl for NGLs.

4. Well abandonment costs for wells with reserves have been included at the property level. Additional abandonment costs associated with non-reserves wells, lease reclamation costs and facility abandonment and reclamation expenses have not been included in this analysis.

5. The forecast price and cost assumptions assume the continuance of current laws and regulations.

6. The extent and character of all factual data supplied to GLJ were accepted by GLJ as represented. No field inspection was conducted. .

7. Sensitivity to the New Alberta Royalty Framework

   Corporate total economic forecasts were rerun to examine the impact of the NRF. The government has not yet clarified certain aspects of the new royalty calculations. Accordingly, high and low sensitivities to the NRF were conducted using the Consultant's Consensus Methodology recommended by the Society of Petroleum Evaluation Engineers, Calgary Chapter. The "NRF High" scenario represents a more optimistic or high value sensitivity of the NRF impact, and the "NRF Low" scenario represents the low value sensitivity. Based on currently available information, the net present value of future net revenue (before income taxes) of proved and probable reserves as at December 31, 2007, based on the NRF High scenario would be $86.0 million and based on the NRF Low scenario would be $79.4 million. The government has stated its intention to consult with industry and review the NRF for unintended consequences.

Reconciliations of Changes in Gross Reserve

RECONCILIATION OF
COMPANY GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL			HEAVY OIL		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
December 31, 2006	332	160	492	1,558	623	2,181
Extensions	103	23	125	0	0	0
Infill Drilling	-	-	-	-	-	-
Improved Recovery	0	0	0	0	0	0
Technical Revisions	(58)	(14)	(73)	408	199	607
Discoveries	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0
Dispositions	(27)	(11)	(39)	0	0	0
Economic Factors	0	0	0	0	0	0
Production	(100)	0	(100)	(191)	0	(191)
December 31, 2007	249	157	406	1,775	822	2,597

FACTORS	NATURAL GAS LIQUIDS Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	CONVENTIONAL NATURAL GAS Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	TOTAL Gross Proved (MBOE)	Gross Probable (MBOE)	Gross Proved Plus Probable (MBOE)
December 31, 2006	446	161	607	10,879	4,683	15,562	4,150	1,724	5,874
Extensions	0	0	0	0	71	71	103	34	137
Infill Drilling	0	0	0	247	62	309	41	10	51
Improved Recovery	0	0	0	0	0	0	0	0	0
Technical Revisions	1	(32)	(31)	122	(1,077)	(956)	370	(26)	344
Discoveries	1	1	2	1,093	556	1,649	184	93	277
Acquisitions	0	0	0	0	0	0	0	0	0
Dispositions	(6)	(4)	(9)	(1,338)	(678)	(2,016)	(256)	(127)	(383)
Economic Factors	0	0	0	0	0	0	0	0	0
Production	(108)	0	(108)	(3,613)	0	(3,613)	(1,001)	0	(1,001)
December 31, 2007	336	126	461	7,390	3,617	11,007	3,591	1,708	5,299

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to ExAlta's assets for the years ended December 31, 2007, 2006 and 2005 and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl) First Attributed	Cumulative at Year End	Natural Gas (MMcf) First Attributed	Cumulative at Year End	Heavy Oil (Mbbl) First Attributed	Cumulative at Year End	NGLs (Mbbl) First Attributed	Cumulative at Year End
Prior thereto	0	0	0	0	178	178	0	0
2005	0	0	0	0	369	547	0	0
2006	0	0	163	163	145	692	7	7
2007	0	0	247	410	136	828	0	7

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl) First Attributed	Cumulative at Year End	Natural Gas (MMcf) First Attributed	Cumulative at Year End	Heavy Oil (Mbbl) First Attributed	Cumulative at Year End	NGLs (Mbbl) First Attributed	Cumulative at Year End
Prior thereto	0	0	0	0	112	112	0	0
2005	0	0	0	0	118	230	0	0
2006	0	0	133	133	51	281	7	7
2007	42	42	347	480	174	456	0	7

In general, once proved and/or probable undeveloped reserves are identified they are scheduled into ExAlta's development plans. Normally, the Corporation plans to develop its proved and probable undeveloped reserves within two years. A number of factors that could result in delayed or cancelled development are as follows:

- changing economic conditions (due to pricing, operating and capital expenditure fluctuations);

- changing technical conditions (production anomalies (such as water breakthrough, accelerated depletion));
- multi-zone developments (such as a prospective formation completion may be delayed until the initial completion is no longer economic);
- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and
- surface access issues (landowners, weather conditions, regulatory approvals).

See "Principal Properties", "Future Development Costs" and "Capital Expenditures" for a description of the Corporation's exploration and development plans and expenditures relating to ExAlta's properties.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

The Corporation does not anticipate any unusually high development costs or operating costs relating to ExAlta's properties, the need to build a major pipeline or other major facility before production of reserves can begin, or contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

Future Development Costs

The following table sets forth development costs deducted in the estimation of the ExAlta's future net revenue attributable to the reserve categories noted below:

	Forecast Prices and Costs (MM$)	
Year	Proved Reserves	Proved Plus Probable Reserves
2008	4	6
2009	3	3
2010	0	0
2011	0	0
2012	0	0
Thereafter	0	0
Total Undiscounted	7	9

On an ongoing basis, Galleon will use internally generated cash flow from operations to finance its capital expenditure program. The cost of funding is not expected to have any effect on disclosed reserves or future net revenue nor make the development of a property uneconomic.

Other Oil and Gas Information

Principal Properties

ExAlta is engaged in the exploration for and development and production of crude oil and natural gas in Western Canada. All of the ExAlta's current operations are in the provinces of Alberta and British Columbia.

The following is a description of ExAlta's oil and natural gas properties as at December 31, 2007, unless otherwise stated. Production stated is gross production to ExAlta. The reserve amounts stated are gross reserves, as at December 31, 2007 based on forecast costs and prices as evaluated in the GLJ Report (see "Reserves Data"). **The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.**

Alexis-Cherhill Focus Area

The Alexis-Cherhill area is situated approximately 100 kilometres west of Edmonton, Alberta. ExAlta's interests in the area are relatively concentrated within a four-by-three-township grid. ExAlta acquired the initial production and land base in the Alexis-Cherhill area in May 2003 for a purchase price of $12.0 million. The properties added approximately 271 boe/d of production and approximately 39,000 net acres of undeveloped land. In addition, the acquisition included exploitation opportunities in the Alexis field and related geological features in adjacent undrilled lands as well as an emerging shallow gas property at West Cove, Alberta.

Through an active drilling program, ExAlta increased production in this area from approximately 271 boe/d at the time of the acquisition to an average of approximately 1,315 boe/d in the fourth quarter of 2007. At December 31, 2007, ExAlta had interests in 44,268 gross (33,854 net) acres of undeveloped land in the Alexis-Cherhill area and currently there 74 (26.5 net) producing wells. Up to four wells are planned in the area in 2008.

ExAlta's main exploration targets are defined by erosional topographic relief on the Mississippian and Jurassic unconformity surfaces and the structural drape of overlying Cretaceous sediments. The hydrocarbon reservoirs of primary interest are carbonates and clastics, both oil and natural gas-prone, and are situated from 250 metres to 1,600 metres depth. ExAlta continues to map exploration plays and integrate the ExAlta's seismic database to identify new opportunities to increase the Corporation's prospect portfolio in the area. ExAlta currently has one major property in the Alexis-Cherhill area, the Alexis field. ExAlta is also active in initiating new exploitation programs at other established fields with incremental oil and natural gas potential in the area, as well as the pursuit of a new regional play pursuing the Lower Cretaceous Ostracod.

Grande Prairie Focus Area

ExAlta entered the Grande Prairie area with the acquisition of the Boundary Lake-Hill and Pouce Coupe oil and natural gas properties in December 2002. ExAlta immediately increased production at the acquired properties from approximately 44 boe/d to 109 boe/d and subsequently increased production to approximately 1,404 boe/d in the fourth quarter of 2007 through drilling. ExAlta held interests in 106,759 gross (59,821 net) acres of undeveloped land in the Grand Prairie area as at December 31, 2007. There are currently 29 (13.0 net) producing wells.

The primary exploration targets are seismically defined, fault-controlled, structural and stratigraphic traps containing Cretaceous, Triassic, and Devonian oil and natural gas reservoirs ranging in depth from 750 metres to 2500 metres. At present, ExAlta has three principal properties in this area: Paradise, Clayhurst, and Eaglesham.

Paradise, British Columbia

ExAlta commenced its exploration programs on the British Columbia side of the Northwest Arch in the second half of 2005 with multi-zone discoveries at Paradise, which is located approximately 50 kilometres northeast of Fort St. John. To date, six zones have been proven productive and one well is planned for 2008 at Paradise.

Clayhurst, Alberta

The Clayhurst property is located 140 kilometres northeast of Grande Prairie. ExAlta entered into a farm-in in the area in late 2005 and subsequently earned a 30 percent interest in five sections (960 net acres) of land through drilling. ExAlta is pursuing Triassic reservoirs as well as overlying Cretaceous prospects on these lands. The ExAlta plans to drill up to two wells in this project area in 2008.

Eaglesham, Alberta

In late October 2005 ExAlta entered into a regional farm-in and joint venture with a senior producer on lands located in the Eaglesham-Tangent area on the Peace River Arch located approximately 100 kilometres northeast of Grande Prairie. ExAlta and a partner committed to drill and complete six Wabamun tests on the farmor's lands to earn a 50 percent interest in six sections. As part of the joint venture, ExAlta acquired access to more than 100 square miles of contiguous proprietary 3-D seismic data in the area, and is operating a 200 square mile regional exploration program. Up to 10 gross wells are planned at Eaglesham in 2008, including established targets down to the Wabamun.

Oil and Gas Wells

The following table sets forth the number and status of wells in which ExAlta had a working interest as at December 31, 2007.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	64	21.9	4	2.9	35	15.5	5	3.8
British Columbia	3	1.5	11	6.6	6	2.6	6	2.7
Total	67	23.4	19	9.5	41	18.1	11	6.5

Properties with no Attributable Reserves

The following table sets out ExAlta's developed and undeveloped land holdings as at December 31, 2007.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	50,846	21,531	150,014	99,889	200,860	121,420
British Columbia	3,955	2,016	10,728	7,806	14,683	9,822
Total	54,801	23,547	160,742	107,695	215,543	131,242

The Corporation expects that rights to explore, develop and exploit 15,362 net acres of ExAlta's undeveloped land holdings will expire by December 31, 2008, a portion of which may be continued by drilling. ExAlta plans to drill or submit application to continue selected portions of the above acreage.

Forward Contracts and Marketing

ExAlta's crude oil and natural gas production is sold to major Canadian marketers on a spot pricing basis. Terms of the agreements include a 30 day evergreen in the case of crude oil and NGLs and a term of one year for natural gas. ExAlta may periodically hedge the price of a portion of its crude oil and natural gas production. ExAlta contracts natural gas transportation for periods of one to five years at volumes based on estimated production from each property.

ExAlta no fixed price physical contracts or costless collar financial derivative contracts in place.

Additional Information Concerning Abandonment and Reclamation Costs

Estimated future abandonment costs related to a property have been taken into account by GLJ in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom. ExAlta uses its internal historical costs to estimate its abandonment and reclamation costs when available. The costs are estimated on an area by area basis. The industry's historical costs are used when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements. ExAlta has 108 net wells for which it expects to incur abandonment and reclamation costs. The abandonment and reclamation obligation included in ExAlta's financial statements differs from the amount deducted in the reserves evaluation, as no allowance was made for reclamation of wellsites or the abandonment and reclamation of any facilities in the GLJ Report. The following table sets forth abandonment costs deducted in the estimation of ExAlta's future net revenue for only those wells to which reserves were assigned:

Forecast Prices and Costs (M$)

Year	Total Proved Abandonment Costs (Undiscounted)	Total Proved plus Probable Abandonment Costs (Undiscounted)
2008	109	69
2009	110	68
2010	82	114
Thereafter	1,549	1,895
Total Undiscounted	1,850	2,146
Total Discounted @ 10%	932	827

Tax Horizon

ExAlta does not expect to pay current income tax for the 2008 fiscal year. Depending on production, commodity prices and capital spending levels, ExAlta may begin paying current income taxes in 2009.

Capital Expenditures

The following table summarizes capital expenditures related to ExAlta's activities for the year ended December 31, 2007:

	(M$)
Property acquisition costs	
Proved properties	-
Undeveloped properties	1,327
Exploration costs	11,000
Development costs	13,935
Dispositions	(8,520)
Total	17,742

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which ExAlta participated during the year ended December 31, 2007:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Light and Medium Oil	2	1.0	2	1.1
Heavy Oil	-	-	1	1.0
Natural Gas	8	4.4	4	2.4
Dry	2	0.9	-	-
Total	12	6.3	7	4.5

See "Principal Properties" for a description of ExAlta's exploration and development plans.

Production Estimates

The following tables disclose, by product, the total volume of ExAlta's gross production estimated by GLJ for 2008 in the estimates of future net revenue from gross proved and gross probable reserves disclosed under "Disclosure of Reserves Data and Other Information".

From Gross Total Proved reserves:	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)	%
Alexis Non-Unit	0	418	1,335	163	803	35
Other Properties	234	131	6,274	112	1,522	65
Total	234	550	7,609	274	2,326	100

From Gross Total Probable reserves:	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)	%
Alexis Non-Unit	0	13	83	10	37	15
Other Properties	32	5	991	5	207	85
Total	32	18	1,074	15	244	100

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	Quarter Ended			
	2007			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production[(1)]				
Light and Medium Crude Oil (Bbls/d)	123	384	223	184
Heavy Oil (Bbls/d)	785	409	505	577
Gas (Mcf/d)	264	261	283	373
NGLs (Bbls/d)	9,179	9,394	9,923	11,194
Combined (BOE/d)	2,701	2,620	2,664	3,000

	Quarter Ended			
	2007			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Price Received (net of transportation)				
Light and Medium Crude Oil ($/Bbl)	95.14	69.50	72.58	51.91
Heavy Oil ($/Bbls)	62.18	56.82	49.34	43.13
Gas ($/Mcf)	5.79	4.91	6.84	7.10
NGLs ($/Bbls)	38.62	34.45	36.77	34.18
Combined ($/BOE)	45.44	39.97	44.68	42.24
Royalties Paid				
Light and Medium Crude Oil ($/Bbls)	3.67	9.50	10.69	2.78
Heavy Oil ($/Bbls)	13.64	10.02	9.07	7.10
Gas ($/Mcf)	1.05	1.32	1.86	1.85
NGLs ($/Bbls)	8.21	9.37	10.26	9.02
Combined ($/BOE)	8.08	7.68	8.35	9.01
Operating Expenses ($/BOE)				
Light and Medium Crude Oil ($/Bbls)	41.65	8.44	4.82	4.07
Heavy Oil ($/Bbls)	8.53	12.74	11.55	11.59
Gas ($/Mcf)	2.17	1.89	1.69	1.64
NGLs ($/Bbls)	13.02	10.97	9.98	9.96
Combined ($/BOE)	13.11	10.85	8.90	9.76
Netback Received ($/BOE)(2)				
Light and Medium Crude Oil ($/Bbls)	49.82	51.56	57.07	45.06
Heavy Oil ($/Bbls)	40.01	34.06	28.72	24.44
Gas ($/Mcf)	2.57	1.70	3.29	3.61
NGLs ($/Bbls)	17.39	14.11	16.53	15.20
Combined ($/BOE)	24.26	21.43	27.43	23.46

Notes:

(1) Before deduction of royalties.
(2) Netbacks are calculated by subtracting royalties and operating costs from revenues.

The following table indicates ExAlta's average daily production from its important fields for the year ended December 31, 2007:

	Light and Medium Crude Oil (Bbls/d)	Heavy Oil (Bbls/d)	Gas (Mcf/d)	NGLs (Bbls/d)	BOE (BOE/d)
Alexis/Cherhill	-	568	3,433	229	1,369
Clayhurst	-	3	1,825	3	310
Eaglesham	227	-	1,436	1	468
Other	-	-	3,222	61	598
Total	227	571	9,916	294	2,745

ExAlta's crude oil production for the year ended December 31, 2007 was 8% light quality crude oil (32° API or greater), 21% heavy oil, 60% natural gas, and 11% liquids.

For the twelve months ended December 31, 2007, approximately 39% of ExAlta's gross revenue was derived from crude oil production and 61% was derived from natural gas production.

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GALLEON

ENERGY INC.

Financial Statements

DECEMBER 31, 2007

Management's Responsibility for Financial Reporting

The accompanying financial statements and all information in the annual report are the responsibility of management. Management has prepared the financial statements in accordance with Canadian generally accepted accounting principles. In the opinion of management, the financial statements have been prepared within acceptable limits of materiality and, when necessary, management has made informed judgments and estimates in accounting for transactions that were not complete at the balance sheet date. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances as indicated in the notes to the financial statements. Financial information contained elsewhere in the annual report has been prepared and reviewed by management to ensure it is consistent with the financial statements.

Management has established systems of 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 generally accepted accounting principles.

The Audit and Reserves Committee is appointed by the Board of Directors, and comprises directors that are not employees of the Corporation. The Committee meets regularly with management, as well as the external auditors, to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues, to satisfy itself that each party is discharging its responsibilities, and to review the financial statements and the external auditors' report. The Board of Directors has approved the financial statements.

Signed "Steve Sugianto"

Steve Sugianto
President and Chief Executive Officer

Signed "Shivon Crabtree"

Shivon M. Crabtree
Vice President Finance and
Chief Financial Officer

March 10, 2008

AUDITORS' REPORT

To the Shareholders of Galleon Energy Inc.

We have audited the consolidated balance sheets of Galleon Energy Inc. as at December 31, 2007 and 2006 and the consolidated statements of earnings, comprehensive income and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2007 and 2006 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Calgary, Canada
March 10, 2008 (except for Note 11 (c)
which is as of March 25, 2008)

Signed "Ernst & Young LLP"
Chartered Accountants

GALLEON ENERGY INC.
Consolidated Balance Sheets
As at December 31

($000s)	2007	2006
ASSETS		
CURRENT		
Accounts receivable	35,406	24,639
Deposits and prepaid expenses	5,459	1,839
Fair value of financial derivative (note 10)	-	190
	40,865	26,668
Goodwill (note 3)	16,022	10,139
Equipment Inventory	2,829	2,536
Property and equipment (notes 3, 4, 5 and 6)	739,643	575,222
	799,359	**614,565**
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	71,044	54,695
Bank loan (note 6)	163,378	122,996
Fair value of financial derivatives (note 10)	9,075	-
	243,497	177,691
Asset retirement obligation (note 5)	25,535	21,432
Future income taxes (note 8)	52,299	32,287
	321,331	231,410
SHAREHOLDERS' EQUITY		
Share capital (note 7)	419,011	339,869
Contributed surplus (note 7)	19,064	11,619
Retained earnings	39,953	31,667
	478,028	383,155
	799,359	**614,565**

See accompanying notes

Approved on behalf of the Board of Directors:

"Signed" "Signed"

William L. Cooke — Director

Fred C. Coles — Director

GALLEON ENERGY INC
Consolidated Statements of Earnings,
Comprehensive Income and Retained Earnings
Years ended December 31

($000s, except per share amounts)	2007	2006
REVENUE		
Petroleum and natural gas revenue	245,203	157,931
Royalties, net of ARTC and GCA	(41,553)	(23,529)
Other income	-	5
	203,650	134,407
EXPENSES		
Operating	44,759	33,675
Transportation	6,024	4,507
General and administration	7,281	5,590
Interest	10,110	4,527
Stock-based compensation (note 7)	8,516	7,713
Accretion	1,949	631
Depletion and depreciation	100,331	60,929
Realized loss on financial derivative (note 10)	3,545	-
Unrealized loss(gain) on financial derivative (note 10)	9,264	(190)
	191,779	117,382
Earnings before taxes	11,871	17,025
Income taxes (note 8)		
Capital and other taxes	879	957
Future income taxes	2,706	2,242
	3,585	3,199
NET EARNINGS AND COMPREHENSIVE INCOME	**8,286**	**13,826**
RETAINED EARNINGS, BEGINNING OF YEAR	31,667	17,841
RETAINED EARNINGS, END OF YEAR	39,953	31,667
NET EARNINGS AND COMPREHENSIVE INCOME PER SHARE (note 7)		
Basic	$0.14	$0.26
Diluted	$0.13	$0.25
Weighted average Class A shares – basic	60,037,422	53,343,857
– diluted	61,827,278	55,907,653

See accompanying notes

GALLEON ENERGY INC.
Consolidated Statements of Cash Flows
Years ended December 31

($000s)	2007	2006
Cash provided by (used in):		
OPERATING ACTIVITIES		
Net earnings	8,286	13,826
Items not requiring cash:		
Future income taxes	2,706	2,242
Depletion and depreciation	100,331	60,929
Accretion	1,949	631
Stock-based compensation	8,516	7,713
Unrealized loss (gain) on financial derivative	9,264	(190)
Abandonment costs	(2,172)	(614)
Change in non-cash working capital	(5,812)	(39)
	123,068	84,498
FINANCING ACTIVITIES		
Issue of common shares	93,257	178,300
Share issue costs	(4,925)	(10,092)
Bank loan	40,382	47,694
	128,714	215,902
INVESTING ACTIVITIES		
Additions to equipment inventory	(293)	(1,429)
Additions to oil and gas properties	(208,344)	(283,348)
Acquisition of oil and gas properties (notes 3 and 4)	(50,919)	(25,396)
Change in non-cash working capital	7,774	9,773
	(251,782)	(300,400)
CHANGE IN CASH	-	-
CASH, BEGINNING OF YEAR	-	-
CASH, END OF YEAR	-	-
SUPPLEMENTARY INFORMATION		
Cash interest paid	10,084	5,040
Cash taxes paid	542	1,208

See accompanying notes

Notes to the Financial Statements
For the years ended December 31, 2007 and 2006

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 symbols "GO.A" and "GO.B".

The financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"), and have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the accounting policies summarized below.

Measurement Uncertainty

The amounts recorded for depletion and depreciation of property and equipment, the provision for asset retirement obligations, the fair value of the financial derivative, the provision for income taxes, and the ceiling test calculation are based on estimates of proven reserves, production rates, oil and natural gas prices, future costs, future prices, and other relevant assumptions. Accruals for royalties and costs are prepared based on estimates when actual amounts are not yet known. Stock based compensation amounts are determined using certain assumptions (see note 7). By their nature, these estimates and assumptions are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future years could be significant.

Cash and cash equivalents

Cash and cash equivalents may include highly liquid short-term investments with initial maturities of three months or less. They are recorded at cost which approximates fair market value.

Property and equipment

Petroleum and natural gas properties and equipment

The Corporation follows the full cost method of accounting whereby all costs related to the exploration for and development of petroleum and natural gas reserves, whether productive or unproductive, are capitalized in one Canadian cost centre. Such costs include land acquisition, drilling, equipping, geological and geophysical and overhead expenses related to exploration and development activities. These costs are depleted on the unit-of-production method using estimated gross proven petroleum and natural gas reserves as determined by independent professional engineers. Petroleum and natural gas reserves are converted to a common unit of measure on an energy equivalent basis of six Mcf of gas to one barrel of oil. Costs of acquiring and evaluating unproven properties are excluded from the depletion calculation until it is determined whether or not proven reserves are attributable to the properties or impairment occurs. Proceeds from the sale of petroleum and natural gas properties and related equipment are applied against capitalized costs, with no gain or loss recognized, unless such a sale would result in a change in the rate of depletion of 20% or more.

Ceiling test

The Corporation evaluates its petroleum and natural gas assets in each reporting period to determine that the costs are recoverable. If the sum of the anticipated undiscounted cash flows from proved reserves, based on expected future escalating product prices and costs, exceed the carrying value of the assets, the costs are considered recoverable. If the carrying value is not considered recoverable, an impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from production of the proved and probable reserves.

Office furniture and equipment

Office furniture, equipment and other assets are recorded at cost and depreciated on a straight-line basis over their estimated useful lives of three to five years.

Equipment Inventory

The Corporation records equipment inventory as a long-term asset on the balance sheet.

Goodwill

Goodwill, at the time of acquisition, represents the excess of the purchase price of a business over the fair value of net assets acquired; thereafter, goodwill is assessed for impairment at least annually. If the fair value of the business is less than the book value, a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the business' other assets and liabilities from the fair value of the business to determine the implied fair value of goodwill and comparing that amount to the book value of goodwill. Any excess of the book value of goodwill over the implied fair value is the impairment amount and will be charged to income in the period of the impairment. For the years ended December 31, 2007 and 2006, no goodwill impairment was required.

Asset retirement obligation

The Corporation follows the recommendations for asset retirement obligations as set out in the CICA Handbook section 3110. This standard requires the recognition and measurement of liabilities related to the legal obligation to abandon and reclaim property, plant and equipment incurred upon acquisition, construction, development and/or normal use of the asset. The initial liability must be measured at fair value and subsequently adjusted for the accretion of discount and changes in the fair value. The asset retirement cost is capitalized as part of property and equipment and depleted into earnings based on units of production. Actual costs incurred upon settlement of the obligations are charged against the liability.

Revenue recognition

Petroleum and natural gas sales are recognized when delivery of the product has been completed and title passes to an external party.

Joint interests

The Corporation's petroleum and natural gas activities may be conducted jointly with others. These financial statements reflect only the Corporation's proportionate interest in such activities.

Future income taxes

The liability method is used in accounting for income taxes. Under this method, future income tax assets and liabilities are recognized based on differences between the financial reporting and tax bases of assets and liabilities, and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in income in the period in which the change is substantively enacted.

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. 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.

Fair values

The carrying values of accounts receivable and accounts payable approximated their fair values at December 31, 2007 due to their short-term nature. The carrying value of the bank loan approximates its fair value due to the floating interest rate on the facility. The financial derivatives are recorded at fair value.

Stock-based compensation

The Corporation follows the accounting standard on stock based compensation as presented in the CICA Handbook section 3870. This standard requires the recognition of stock-based compensation expense for "awards to" or "grants to" employees and non-employees using the fair value method.

The standard requires the fair value of all stock based compensation awards to be expensed over the vesting period of the award with an offsetting credit to contributed surplus. The Black-Scholes option pricing model has been used to calculate the fair value of the stock options granted. Consideration paid by optionees on the exercise of stock options is credited to share capital together with any amount previously included in contributed surplus.

2. CHANGES IN SIGNIFICANT ACCOUNTING POLICIES

On January 1, 2007, Galleon adopted six new accounting standards that were issued by the Canadian Institute of Chartered Accountants ("CICA"): Section 1506 "Accounting Changes;" Section 1530 "Comprehensive Income;" Section 3251 "Equity;" Section 3855 "Financial Instruments - Recognition and Measurement;" Section 3861, "Financial Instruments - Disclosure and Presentation" and Section 3865 "Hedges."

CICA Section 1506, "Accounting Changes," provides expanded disclosures for changes in accounting policies, accounting estimates and corrections of errors. Under the new standard, accounting changes should be applied retroactive unless otherwise permitted or where impracticable to determine. As well, voluntary changes in accounting policy are made only when required by a primary source of GAAP or the change results in more relevant and reliable information.

CICA Section 1530, "Comprehensive Income", introduces a new requirement to temporarily present certain gains and losses from changes in fair value outside net income. It includes unrealized gains and losses, such as: changes in the currency translation adjustment relating to self-sustaining foreign operations; unrealized gains or losses on available-for-sale investments; and the effective portion of gains or losses on derivatives designated as cash flow hedges. The application of this revised standard did not result in comprehensive income being different from net earnings for the periods presented.

CICA Section 3251, "Equity", establishes standards for the presentation of equity and changes in equity during the reporting periods. The requirements of this section have been effected in the presentation of the Consolidated Statements of Changes in Shareholder' Equity. The application of this standard did not have a significant impact on Galleon's consolidated financial statements.

CICA Section 3855 "Financial Instruments – Recognition and Measurement" prescribes when a financial instrument is to be recognized on the balance sheet and at what amount. It also specifies how financial instrument gains and losses are to be presented. All financial instruments are classified into one of the following five categories: held for trading, held-to-maturity, loans and receivables, available-for-sale financial assets, or other financial liabilities. Initial and subsequent measurement and recognition of changes in the value of financial instruments depends on their initial classification. All derivative financial instruments are classified as held for trading financial instruments and are measured at fair value, even when they are part of a hedging relationship. All gains and losses are included in net earnings in the period in which they arise. The application of CICA Section 3855 does have an impact on Galleon's consolidated financial statements.

CICA Section 3865 provides alternative treatments to Section 3855 for entities which choose to designate qualifying transactions as hedges for accounting purposes. It replaces and expands on Accounting Guideline 13 "Hedging Relationships", and the hedging guidance in Section 1650 "Foreign Currency Translation" by specifying how hedge accounting is applied and what disclosures are necessary when it is applied. Galleon has not designated its financial derivative instrument as a hedge, therefore this section does not have an impact on Galleon's consolidated financial statements.

In addition, the Company has assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have a significant impact on the Corporation:

As of January 1, 2008, Galleon will be required to adopt two new CICA standards, Section 3862 "Financial Instruments – Disclosures" and Section 3863 "Financial Instruments – Presentation," which will replace Section 3861 "Financial Instruments – Disclosure and Presentation." The new disclosure standard increases the emphasis on the risks associated with both recognized and unrecognized financial instruments and how those risks are managed. The new presentation standard carries forward the former presentation requirements. The Corporation is assessing the impact on its consolidated financial statements.

As of January 1, 2008, Galleon will be required to adopt Section 1535 "Capital Disclosures," which will require companies to disclose their objectives, policies and processes for managing capital. In addition, disclosures are to include whether companies have complied with externally imposed capital requirements. The Corporation is assessing the impact on its consolidated financial statements of the new capital disclosure requirements.

CICA 1400, General Standards of Financial Statement Presentation, was amended to include requirements to assess and disclose an entity's ability to continue as a going concern. The new requirements are effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2008. Galleon does not expect the adoption of this standard to have an impact on its financial statements.

CICA 3031, Inventories, replaces CICA 3030, Inventories. The new standard is the Canadian equivalent to International Financial Reporting Standard IAS 2, Inventories. CICA 3031 applies to interim and annual financial statements relating to fiscal years beginning on or after January 1, 2008. Galleon does not expect the adoption of this standard to have an impact on its financial statements.

CICA 3064, Goodwill and Intangible Assets, will replace CICA 3062, Goodwill and Other Intangible Assets, and results in withdrawal of CICA 3450, Research and Development Costs, and amendments to Accounting Guideline (AcG) 11, Enterprises in the Development Stage and CICA 1000, Financial Statement Concepts. The standard intends to reduce the differences with IFRS in the accounting for intangible assets as under current Canadian standards, more items are recognized as assets. The objectives of CICA 3064 are to reinforce the principle-based approach to the recognition of assets only in accordance with the definition of an asset and the criteria for asset recognition. The application of the concept of matching revenues and expenses is that the current practice of recognizing as assets items that do not meet the definition and recognition criteria is eliminated. The standard will also provide guidance for the recognition of internally developed intangible assets (including research and development activities), ensuring consistent treatment of all intangible assets, whether separately acquired or internally developed. These changes are effective for fiscal years beginning on or after October 1, 2008, with early adoption encouraged. Galleon is evaluating the effects of adopting this standard.

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 current 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. Companies will be required to provide comparative IFRS information for the previous fiscal year. Galleon is currently evaluating the impact of adopting IFRS.

3. ACQUISITION OF PARTNERSHIP

On February 1, 2007, the Corporation closed a transaction resulting in an acquisition of an interest in a partnership and the minority partnership's holdings resulting in a 100% consolidated interest. The partnership holds oil and gas assets within Galleon's core area of Dawson, Alberta. The total consideration of $28.7 million was paid in cash. The business combination has been accounted for as a purchase as at the closing date of the transaction, with the purchase price allocated to assets and liabilities as follows:

Allocation of Purchase Price	$
Property and equipment	30,874
Goodwill	5,883
Asset retirement obligation	(980)
Future income taxes	(7,045)
	28,732

Calculation of Purchase Price	
Cash for purchase of interest	28,664
Transaction costs	68
	28,732

4. PROPERTY AND EQUIPMENT

On July 3, 2007 the Corporation purchased oil and gas properties in the Eaglesham/Kakut area of Alberta for cash of $15.7 million. An asset retirement obligation of $436,367 has been recorded for this property purchase.

On June 29, 2007 the Corporation purchased oil and gas properties in the Shadow area of Alberta for cash of $5.1 million. An asset retirement obligation of $65,750 has been recorded for this property purchase.

On June 2, 2006, the Corporation purchased oil and gas properties from a senior oil and gas producer in the Peace River Arch area of Alberta. The cash purchase price was $25.4 million including closing adjustments.

As at December 31, 2007, $105.8 million (December 31, 2006 - $76.5 million) of undeveloped land, seismic and equipment under construction have been excluded from and $110.8 million (December 31, 2006 - $95.0 million) in future development costs have been added into the full cost pool for depletion purposes. For the year ended December 31, 2007, $1,035,950 (December 31, 2006 – $660,500) of exploration salaries have been capitalized.

As at December 31, 2007	Cost $	Accumulated depletion $	Net book value $
Petroleum and natural gas properties & equipment	952,752	(213,401)	739,351
Office furniture and equipment	1,025	(733)	292
	953,777	**(214,134)**	**739,643**

As at December 31, 2006	Cost $	Accumulated depletion $	Net book value $
Petroleum and natural gas properties & equipment	688,354	(113,285)	575,069
Office furniture and equipment	671	(518)	153
	689,025	**(113,803)**	**575,222**

The Corporation has performed the ceiling test using the following benchmark reference prices at December 31, 2007 for the years 2008 to 2013 and adjusted for commodity differentials specific to the Corporation. Beyond year 2013, the price forecast escalates on average 2% per year. A foreign exchange rate of $1.00 US to $1.00 CDN was used. No impairment was required.

Benchmark Reference Price Forecasts:

	2008	2009	2010	2011	2012	2013
WTI oil USD/Bbl	90.00	86.52	84.87	83.32	82.78	82.19
Alberta spot gas $Cdn/Mcf	6.69	7.29	7.18	7.13	7.19	7.21

5. ASSET RETIREMENT OBLIGATION

The Corporation's asset retirement obligation results from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Corporation estimates the total undiscounted amount of cash flows required to settle its asset retirement obligation is approximately $57.6 million, which will be incurred over the next 19 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.

Years ended December 31	2007 $	2006 $
Balance, beginning of year	21,432	11,186
Accretion expense	1,949	631
Liabilities incurred	3,346	6,149
Liabilities acquired	980	1,200
Revision of liabilities	-	2,880
Settlement of liabilities	(2,172)	(614)
Balance, end of year	**25,535**	**21,432**

6. AVAILABLE CREDIT FACILITY

The Corporation has extendible revolving term credit facilities of $220 million in place with a bank syndicate. The facilities bear interest at rates ranging from the bank's prime rate to prime plus 0.75% per annum on $210 million and at rates ranging from the bank's prime rate plus 0.95% to prime plus 1.75% on $10 million based on the Corporation's debt to cash flow ratio. The Corporation may also borrow at the prevailing Banker's Acceptance rate. For the year ended December 31, 2006, the Corporation's effective interest rate was 6.16% (December 31, 2006 – 5.38%). 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, 2007, an amount of $163.3 million was drawn against the credit facilities (December 31, 2006 - $123.0 million).

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, convertible (at the option of the Corporation) at any time after December 31, 2007 and before December 31, 2008, into Class A shares. The conversion factor is calculated by dividing $10 by the greater of $1 and the then current market price of Class A shares. If conversion has not occurred by the close of business on December 31, 2008, the Class B shares become convertible (at the option of the shareholder) into Class A shares on the same basis. Effective February 1, 2009, all remaining Class B shares will be deemed to be converted to Class A shares.

Issued and outstanding **Class A shares**	Number of Shares	Amount $
Balance at December 31, 2005 (a)	47,740,326	169,256
Issued for cash (b)	7,415,700	135,196
Issue of flow-through shares for cash (b)	1,580,000	40,046
Issued for cash on exercise of stock options	976,051	3,058
Tax effect of flow through shares	-	(6,800)
Share issue costs, net of tax of $3,148	-	(6,944)
Transfer from contributed surplus	-	850

Balance at December 31, 2006 (a)	57,712,077	334,662
Issued for cash (b)	1,869,200	30,001
Issue of flow-through shares for cash (b)	2,944,900	60,000
Issued for cash on exercise of stock options	689,375	3,256
Tax effect of flow through shares	-	(11,692)
Share issue costs, net of tax of $1,431	-	(3,494)
Transfer from contributed surplus	-	1,071
Balance at December 31, 2007	**63,215,552**	**413,804**
Class B shares		
Balance at December 31, 2007,December 31, 2006 and December 31, 2005	922,500	5,207
Total share capital at December 31, 2007	**64,138,052**	**419,011**

a) On June 7, 2006, the shareholders of the Corporation approved a three-for-two Class A share split. The number of Class A shares above has been restated to reflect the share split.

b) On September 28, 2007, the Corporation issued 1,869,200 Class A shares at $16.05 per share and 1,463,400 flow-through Class A shares at $20.50 per share pursuant to a public offering for aggregate gross proceeds of $60.0 million. Galleon is obligated to incur qualifying exploration expenses of $30.0 million prior to December 31, 2008. As at December 31, 2007 $30.0 million of the required qualifying expenditure remains to be incurred.

On April 19, 2007, the Corporation issued 1,481,500 flow-through Class A shares at $20.25 per share by way of private placement for gross proceeds of $30.0 million. Galleon is obligated to incur qualifying exploration expenses of $30.0 million prior to December 31, 2008. As at December 31, 2007 $5.4 million of the required qualifying expenditure remains to be incurred.

On February 14, 2006, the Corporation issued 3,405,000 Class A shares at $16.17 per share by way of private placement for gross proceeds of $55.0 million.

On July 25, 2006, the Corporation issued 2,985,000 Class A shares at $20.15 per share and 780,000 flow-through Class A shares at $25.70 per share pursuant to a public offering for gross proceeds of $80.2 million. The Corporation has incurred all the required qualifying expenditures related to these flow-through shares.

On November 16, 2006 the Corporation issued 1,025,700 Class A shares at a price of $19.50 per share and 800,000 flow-through Class A shares at a price of $25.00 per share pursuant to a public offering for gross proceeds of $40.0 million. The Corporation has incurred all the required qualifying expenditures related to these flow-through shares.

The Corporation has a share option plan which was approved on May 19, 2005 and amended on August 25, 2005 and June 19, 2007. In 2007 the exercise price of each option equals the market price of the Corporation's Class A shares on the date of the grant. Compensation expense is recognized as the options vest (one third immediately and one third on each of the first and second 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 and Class B 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 and Class B shares. Class A shares have been reserved for all options granted.

As at December 31	2007 $	2006 $
Contributed surplus, beginning of period	11,619	4,756
Stock based compensation expense	8,516	7,713
Transfer to share capital	(1,071)	(850)
Contributed surplus, end of period	**19,064**	**11,619**

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 2.00-4.51%; dividend yield of 0%; volatility factors of the market price of the Corporation's Class A shares of 36-46%; and, an average expected life of the options of 3 years.

	Number of Shares[1]	Weighted Average Exercise Price [1] $
Outstanding, December 31, 2005	4,638,876	5.63
Granted	1,647,500	19.13
Exercised	(976,051)	(3.13)
Outstanding, December 31, 2006	5,310,325	10.28
Granted	1,720,000	15.51
Cancelled	(130,000)	(9.60)
Exercised	(689,375)	(4.72)
Outstanding, December 31, 2007	**6,210,950**	**12.36**

[1] Restated to reflect the three-for-two Class A share split in June 2006.

The following table summarizes information regarding stock options at December 31, 2007:

Options Outstanding				Options Exercisable	
Exercise Price $	Number Outstanding	Weighted Average Remaining Life (Years)	Weighted Average Exercise Price $	Number Exercisable	Weighted Average Exercise Price $
0.23	230,000	0.77	0.23	230,000	0.23
2.84-3.33	450,750	1.12	2.94	450,750	2.94
5.33-5.73	185,700	1.62	5.65	185,700	5.65
6.67-8.70	1,495,500	2.37	6.98	1,495,500	6.98
9.67-14.33	1,296,500	3.74	13.39	856,500	13.02
14.51-21.77	2,320,000	4.01	17.77	1,141,665	18.31
22.67-22.83	232,500	3.27	22.73	155,000	22.72
	6,210,950	**3.13**	**12.36**	**4,515,115**	**10.73**

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. For the year ended December 31, 2007, 2,132,500 options have been excluded from the diluted earnings per share calculation as they are anti-dilutive. The diluted weighted average number of Class A shares outstanding after deemed conversion of the Class B shares is 62,403,666 (December 31, 2006 – 56,394,883). The prior year amounts have been restated to reflect the three-for-two Class A share split in June 2006.

8. INCOME TAXES

The future income tax liability is comprised of the following temporary differences as at December 31:

	2007	2006
	$	$
Property and equipment	47,108	38,740
ACRI benefit	(870)	(870)
Share issue costs	(3,716)	(4,031)
Asset retirement obligation	(209)	(286)
Non-capital losses	(27,020)	(1,321)
Partnership income tax deferral	39,517	-
Financial derivative	(2,511)	55
Future income tax liability	**52,299**	**32,287**

The provision for income tax differs from the amount that would have been expected if the reported earnings had been subject only to the statutory Canadian income tax rate of 32.45% (December 31, 2006 – 35.07%).

Years ended December 31	2007	2006
	$	$
Earnings before income tax	11,871	17,025
Corporate tax rate	32.45%	35.07%
Expected tax	3,852	5,971
Increase (decrease) in taxes resulting from:		
Non-deductible crown payments	-	2,584
Resource allowance	-	(2,524)
Non-deductable items	25	(154)
Stock-based compensation	2,763	2,705
Statutory tax rate changes	(3,652)	(5,972)
Deductible capital taxes	(285)	(336)
Other	3	(32)
	2,706	2,242

As at December 31, 2007, Galleon has approximately $544.6 million (December 31, 2006 – $440.5 million) of tax deductions for Canadian income tax purposes.

9. COMMITMENTS

Drilling Rig:
The Corporation has entered into a Master Daywork Contract whereby it is entitled to the use of a drilling rig for a two year period which commenced in November, 2007. Future minimum payments under this contract are as follows:

Year	Amount $
2008	2,344
2009	4,070

Equipment:
The Corporation has made installment payments of $482,940 related to equipment which will be delivered in the first quarter of 2008. The installment payments have been recorded on the balance sheet as prepaid. Additional future commitments for this equipment are $1.1 million.

Minimum Lease Payments:
At December 31, 2007 the Corporation has committed to future minimum payments under operating leases that cover office space as follows:

Year	Amount $
2008	2,333
2009	2,619
2010	1,768

The above commitment includes an estimate of the Corporation's share of operating expenses, utilities and taxes for the duration of the office lease.

Flow-through Shares:
In connection with the Corporation's flow-through share offerings in 2006, Galleon was obligated to spend $40.0 million on qualifying exploration expenses prior to December 31, 2007. As at December 31, 2007, there are no remaining capital expenditures to be incurred.

In connection with the Corporation's flow-through share offerings in 2007, Galleon is obligated to spend $60.0 million on qualifying exploration expenses prior to December 31, 2008. As at December 31, 2007, $35.4 million of the required capital expenditures remains to be incurred.

Litigation:
The Corporation is involved in various other 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

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 derivative ("financial instruments"). The carrying value of accounts receivable and accounts payable approximated their fair values at December 31, 2007 due to their short-term nature. The carrying value of the bank loan approximates its fair value due to the floating interest rate on the facility. The fair value of the financial derivative is recognized on the balance sheet as described below.

Credit risk:
A substantial portion of the Corporation's accounts receivable are with customers in the energy industry and are subject to normal industry credit risk. Galleon generally grants unsecured credit but routinely assesses the financial strength of its customers.

Interest rate risk:
The Corporation is exposed to interest rate risk to the extent that changes in market interest rates will impact the Corporation's debts that have a floating interest rate.

The Corporation has the following costless collar financial derivatives in place for crude oil as at December 31, 2007:

Crude Oil:		
January 1, 2008 – December 31, 2008	2,000 Bbl/d	WTI CDN $70.00-$80.75/Bbl
January 1, 2008 – December 31, 2008	1,000 Bbl/d	WTI USD $75.00-$100.00/Bbl

Galleon has entered into the above financial derivative contracts for the purpose of protecting its funds generated from operations from the volatility of crude oil prices. For the year ended December 31, 2007, the previously settled financial derivative contracts had realized losses of $3,544,859. As described in note 2, 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. The fair value is based on quoted market prices. At December 31, 2007 the fair value was a liability of $9,075,000.

Subsequent to December 31, 2007 the Corporation entered into the following costless collar physical derivative contract for natural gas:

Natural Gas:		
February 1, 2008 – December 31, 2008	10,000 GJ/day	CDN $6.00-$8.00 GJ

Galleon has entered into the above physical derivative contract for the purpose of protecting its funds generated from operations from the volatility of natural gas prices.

11. SUBSEQUENT EVENTS

a) On January 16, 2008 the Corporation successfully completed the acquisition of all of the outstanding common shares of ExAlta Energy Inc. ("ExAlta"), for total consideration of approximately $110.0 million by the issuance of, in aggregate, approximately 4.33 million Class A shares to shareholders of ExAlta. In addition Galleon assumed approximately $47.9 million of net debt (including associated deal costs) pursuant to a plan of arrangement (the "Arrangement"). Pursuant to the Arrangement the previous shareholders of ExAlta were entitled to receive, for each outstanding common share of ExAlta 0.118 of a Class A Share of Galleon.

b) Subsequent to December 31, 2007 upon closing the acquisition of ExAlta, Galleon's extendible revolving term credit facility was increased to $265 million comprised of a lending facility of $250 million and an acquisition facility of $15 million.

c) Galleon has entered into an agreement to purchase a non-listed company ("Privateco") for consideration of $67.2 million which includes positive working capital of approximately $3.8 million. The acquisition price will be paid by the issuance of approximately 4 million Class A shares of Galleon. The acquisition will be completed by way of a plan of arrangement and is subject to receipt of approval by not less than 66 2/3% of the shareholders of Privateco that vote on the resolution, court approval and required regulatory approvals. The acquisition is expected to close prior to the end of May 2008.

12. COMPARATIVE FIGURES

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

GALLEON
ENERGY INC.

Management Discussion and Analysis

DECEMBER 31, 2007

Management's Discussion and Analysis

This Management's Discussion & Analysis ("MD&A") is intended to assist in the understanding of the trends and significant changes in the financial condition and results of operations of Galleon Energy Inc. ("Galleon" or the "Corporation") for the year ended December 31, 2007 with comparisons to the year ended December 31, 2006. 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 audited consolidated financial statements for the year ended December 31, 2007.

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. Barrels of oil equivalent ("BOE") 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, 2008.

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, growth expectations within the Corporation, expected production and production increases, drilling plans, expected growth areas, drilling plans and the timing thereof, budgeted commodity prices, plans to reduce operating costs for heavy oil, planned facilities expansion and the effect of new facilities, expected operating costs, general and administrative expenses and interest costs, and capital expenditures, the timing thereof and the method of funding 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. Readers are cautioned that the foregoing list of factors 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.

2007 Performance

Volume growth in 2007 has delivered significant value. The successful development and expansion of the three key projects, Puskwa, Dawson Montney gas and Eaglesham, has resulted in sustainable growth for the future.

- Net present value of estimated future net revenue before tax from proved plus probable reserves based on forecast prices and costs discounted at 10% reached $1,112 million, a 24% increase over December 31, 2006;
- Gross proved plus probable reserves grew to 59.5 million BOE, an increase of 18% over December 31, 2006 – over 43% of this increase was due to growth in light oil reserves;
- Gross proved reserves grew to 34.1 million BOE, an increase of 20%;
- Gross proved plus probable reserve life index was 11.1 years based on average Q4 2007 production;
- Production on a proved plus probable basis was replaced 2.85 times;
- Gross proved plus probable reserves were 37 % light oil, 42 % natural gas, 19 % heavy oil and 2 % natural gas liquids;
- Access to over 1 million gross acres of land, approximately 80% net owned, has been assembled;
- An inventory of over 725 drilling locations has been identified.

2007 Financial Highlights

- Delivered solid drilling success: drilled 93 gross wells resulting in 49 (44.5 net) natural gas wells, 29 (26.7 net) light oil wells and 5 (3.6 net) heavy oil wells; a success rate of 89%;
- Averaged daily production of 13,429 BOE: natural gas – 45.7 MMcf and crude oil and NGLs – 5,813 Bbl, an increase of 43% from 2006; with an operating netback of $29.14/BOE;
- Generated funds from operations of $131.1 million ($2.18 per basic share), an increase of 54% from 2006;
- Reached revenues of $245.2 million, an increase of 55% compared to 2006;
- Recorded earnings of $17.6 million ($0.29 per basic share) excluding an unrealized loss of $9.3 million recorded based on a mark to market value on crude oil costless collar contracts;
- Spent $208.3 million on exploration and development activities plus property acquisitions of $52.1 million;
- Completed two share equity issuances for gross proceeds of $90.0 million and the issuance of 4,814,100 Class A shares;
- Increased the extendible revolving bank credit facility to $220 million; and
- Approved a $200 million capital budget for 2008 with funding planned to be generated from operations.

Annual Information

($000s)	2007	2006	2005
Revenues	**245,203**	157,931	135,050
Funds from Operations[1]	**131,052**	85,151	78,079
Per share, basic[1]	**2.18**	1.60	1.78
Per share, diluted[1]	**2.12**	1.52	1.68
Net Earnings	**8,286**	13,826	19,620
Per share, basic	**0.14**	0.26	0.45
Per share, diluted	**0.13**	0.25	0.42
Total Assets	**799,359**	614,565	352,619
Net debt	**193,557**	151,213	93,783
Total Long-term Financial Liabilities	**-**	-	-

[1] Funds from operations and funds from operations per share is not a standard measure under GAAP and may not be comparable to similar measures presented by other companies. Management believes that funds flow per share is a useful supplementary measure that may assist investors in assessing the underlying per share value of the Corporation.
[2] See " Non-GAAP Measurements"

On May 18, 2005, Galleon completed a significant acquisition of oil and gas properties in Dawson, Alberta for cash of $91.4 million, net of closing adjustments. The acquisition resulted in year-over-year increase to funds from operations, net income and total assets.

On February 1, 2007, the Corporation closed a transaction resulting in an acquisition of an interest in a partnership and the minority partnership's holdings resulting in a 100% consolidated interest. The partnership holds oil and gas assets within Galleon's core area of Dawson, Alberta. The total consideration of $28.7 million was paid in cash. The acquisition of the partnership and its' holdings increased funds from operations and total assets compared to the prior year. The decrease in net income in 2007 compared to 2006 is due to the fair value of financial derivatives recorded based on quoted market prices. At December 31, 2007 the fair value was a unrealized loss of $9,264,400.

Results of Operations

Comparative financial results for the year are as follows:

Year ended December 31	**2007**		2006	
	4,901,518 BOE		3,420,198 BOE	
($000s)		$/BOE		$/BOE
Revenues	**245,203**	**50.03**	157,931	46.18
Royalties	**(51,586)**	**(10.52)**	(32,900)	(9.62)
ARTC and GCA	**10,033**	**2.05**	9,371	2.74
Transportation costs	**(6,024)**	**(1.23)**	(4,507)	(1.32)
Operating costs	**(44,759)**	**(9.13)**	(33,675)	(9.85)
Net	**152,867**	**31.20**	96,220	28.13
Other revenue	**-**	**-**	5	-
G&A	**(7,281)**	**(1.49)**	(5,590)	(1.63)
Interest costs	**(10,110)**	**(2.06)**	(4,527)	(1.32)
Loss on financial derivative	**(3,545)**	**(0.72)**	-	-
Capital and other taxes	**(879)**	**(0.18)**	(957)	(0.28)
Funds from operations[1]	**131,052**	**26.75**	85,151	24.90

[1] See "Non-GAAP Measurements"

Petroleum and Natural Gas Revenues

Year ended December 31	2007		2006	
($000s)		%		%
Light oil	**98,564**	**40**	50,139	32
Heavy oil	**27,776**	**11**	25,131	16
NGLs	**5,736**	**3**	2,919	2
Natural gas	**112,299**	**46**	79,125	50
Royalty income	**828**	**-**	617	-
Total	**245,203**	**100**	157,931	100

Revenues for the year ended December 31, 2007 increased 55% to $245.2 million from $157.9 million in the prior year due to a 43% increase in average production volumes. As well the overall price received increased to $50.03/BOE from $46.18/BOE a year ago as a result of higher commodity prices. The average oil price increased 15% year- over -year excluding the 2007 crude oil financial derivative contract. Galleon's petroleum products are sold at spot reference prices based on U.S. dollars for crude oil and AECO for natural gas. The 2007 decline in the value of the U.S. dollar has had a negative effect on the oil revenues received by Galleon.

Production

Year ended December 31	2007		2006	
		%		%
Light oil (Bbls/d)	**3,562**	**26**	1,963	21
Heavy oil (Bbls/d)	**2,005**	**15**	1,845	20
NGLs (Bbls/d)	**246**	**2**	131	1
Natural gas (Mcf/d)	**45,697**	**57**	32,584	58
BOE/d (6:1)	**13,429**	**100**	9,370	100

Average production volumes for 2007 of 13,429 BOE/d increased by 43% compared to 9,370 BOE/d in 2006. By product, light oil volumes increased 81%, natural gas volumes increased 40%, and heavy oil volumes increased 9%. Light oil production increased as a result of drilling success in the Puskwa, Eaglesham and newly discovered areas of McLeans Creek and Kimiwan. Natural gas production increased as a result of Dawson Montney gas, Eaglesham and Puskwa drilling success. Heavy oil production increased slightly as a result of optimization techniques and minor workovers at Edam.

Commodity Pricing and Marketing

Petroleum products are sold to major Canadian marketers at spot reference prices based on US WTI for crude oil and AECO for natural gas. As a means of managing the risk of commodity price volatility, for the period from April 1, 2007 – October 31, 2007 15,000 GJ per day was contracted at prices ranging between $6.50 per GJ to $8.12 per GJ. For the period December 31, 2007, Galleon realized gains of $3,993,621 on its gas contracts. As well in 2007 Galleon realized a loss of $3,544,859 on crude oil financial derivative contracts for 1,000 Bbl per day for the period from January 1, 2007 – December 31, 2007 and 2,000 Bbl per day for the period from July 1, 2007 – December 31, 2007.

Galleon entered into one term natural gas contract and two crude oil financial contracts for 2008. The natural gas contract for 10,000 GJ/day was put in place on January 8, 2008 and has a term from February 1 to December 31, 2008 with pricing subject to a costless collar of $6.00/GJ and $8.00/GJ Canadian. For crude oil, Galleon implemented one costless collar contract on 2,000 Bbl/day, fixing a floor price of WTI CDN $70.00/Bbl and a ceiling of WTI CDN $80.75/Bbl for the period January 1, 2008 to December 31, 2008. A second crude oil costless collar contract was also implemented on 1,000 bbl/day, fixing a floor price of $75.00 WTI USD and a ceiling of $100.00 WTI USD for the period January 1, 2008 to December 31, 2008. See "Financial Instruments". An unrealized loss of $9,264,400 was recorded based on the mark to market value at December 31, 2007 of these 2008 financial contracts.

Prices (net of transportation)

Year ended December 31	2007	2006
Light oil ($/Bbl)	**74.77**	68.81
Heavy oil ($/Bbl)	**37.39**	36.75
Total oil including financial derivative contract ($/Bbl)	**59.56**	53.27
Total oil with out financial derivative contract ($/Bbl)	**61.31**	53.27
Natural gas ($/Mcf)	**6.54**	6.44
NGLs ($/Bbl)	**63.94**	60.84

The average light oil price (excluding the financial derivative contract) received for 2007 was $74.77/Bbl, an increase of 9% compared to $68.81/Bbl in the prior year. The average heavy oil price was $37.39/Bbl, an increase of 2% compared to $36.75/Bbl in the prior year. For 2008, management has budgeted an average WTI price of USD $75.00.

The average natural gas price received for 2007 was $6.54/Mcf, an increase of 2% compared to $6.44/Mcf in the prior year. For 2008, management has budgeted an average AECO price of $6.25/Mcf.

Performance by Property

Year ended December 31	2007			2006			
	Production		Operating netbacks/ BOE [1]	Production		Operating netbacks/ BOE[1]	2007 Funds from operations[2]
	BOE/d	%	$	BOE/d	%	$	%
Puskwa	**2,125**	**16**	**52.31**	657	7	55.55	**28**
Dawson Montney gas	**3,406**	**25**	**28.50**	1,120	12	23.18	**25**
Eaglesham	**1,763**	**13**	**28.91**	280	3	35.42	**13**
Dawson	**3,025**	**23**	**29.60**	4,010	43	28.62	**23**
Calais	**715**	**5**	**25.03**	1,002	11	26.62	**5**
Edam and other heavy oil	**2,005**	**15**	**8.33**	1,846	20	7.57	**4**
B.C.	**212**	**2**	**27.18**	225	2	26.01	**1**
Other	**178**	**1**	**12.53**	230	2	18.73	**1**
	13,429	**100**	**29.14**	9,370	100	25.39	**100**

[1] Operating netbacks/BOE exclude ARTC and GCA and are calculated by subtracting royalties and operating costs from revenues divided by average annual production.
[2] See "Non-GAAP Measurements".

Galleon continued to expand the Puskwa Beaverhill Lake ("BHL") light oil project in 2007 and has drilled 12 wells with 100% success thereby expanding the pool boundaries to approximatey ten miles in length. Throughout most of 2007, this pool has been produced under primary recovery. Galleon believes, based on analogous BHL pools, that the reservoir lends itself to enhanced oil recovery which can significantly increase the recoverable oil from the pool. Two enhanced recovery schemes have been initiated and have performed well to date. Puskwa contributed 28% of annual funds from operations from 16% of total production. Producing wells generated strong operating netbacks of $52.31/BOE driven by low operating costs of $4.54/BOE and high light oil prices, net of transportation, of $77.31/bbl. The high light oil price received is indicative of the quality of the 38 degree API sweet oil. Galleon plans to drill up to 13 new wells in the Puskwa area in 2008 and expand the enhanced recovery scheme areas. Based on Galleon's past experience exploiting BHL pools, 40 acre spacing is necessary for optimum drainage of the reservoir. As the current well spacing is 160 acres, there is significant potential for additional infill drilling in this project and applications for downspacing have been initiated. A significant Montney resource play has been identified in this area and will be delineated in 2008.

In 2007 Galleon expanded the Dawson Montney gas fairway by 10 miles to encompass an area approximately 35 miles long by 12 miles wide. Galleon has achieved a drilling success rate of over 90% and has identified in excess of 350 locations in this project. Production of Montney gas at Dawson increased by 204% compared to 2006 due to a successful drilling program. Operating netbacks increased by 23% to $28.50/BOE due primarily to lower operating costs of $4.88/BOE compared to $6.04/BOE in 2006. Operating costs per BOE are low due to control of the facilities in the area and increased production rates. Dawson Montney Gas average production was 3,406 BOE/day and contributed 25% of the annual funds from operations from 25% of production. Galleon has assembled a large contiguous land block at Dawson covering over 500 square miles. The future plan for this project is to continue to explore for new Montney pools located along trend and to further develop the existing projects which includes down spacing to 2 wells per section. Galleon plans to drill up to 34 wells on this play and to expand the natural gas facilities to capacity of 40 MMcf/d in 2008, subject to natural gas prices.

Liquids rich natural gas and light oil production at Eaglesham averaged 1,763 BOE/day in 2007. Galleon has drilled 15 wells in 2007 with 87% success and has identified new light oil pools in Eaglesham. Eaglesham contributed 13% of 2007 annual funds from operations from 13% of production. Year to date operating netbacks of $28.91/BOE reflect a low operating cost structure of $5.82/BOE. Control of the facilities in the area has enabled Galleon to control operating costs. A new 10,000 BOE/day oil battery with significant water disposal capabilities and expansion of the existing gas plant were completed in early 2008. The battery and plant expansion was required to accommodate existing and significant production growth expected in 2008. Galleon spent $3.0 million on 3D seismic in the Eaglesham area in 2007 and based on this seismic has built a prospect inventory of over 50 locations. Galleon plans to drill up to 17 wells in this area in 2008 expanding the Wabamun oil play on the existing Galleon acreage trend.

The Dawson area averaged 3,025 BOE/day and contributed 23% to Galleon's annual funds from operations from 23% of total production. Production from the area decreased overall by 25% compared to the previous year as a result of natural gas declines due to reduced capital spending. Light oil production increased 26% in the Dawson area in fourth quarter 2007 compared to the prior year 2006, mainly due to new light oil discoveries at McLeans Creek. Galleon drilled 5 wells in McLeans Creek with an 80% success rate. The majority of this production came on in December 2007 and averaged 745 BOE/day in the month of December. Galleon plans to drill up to 8 wells in the first quarter of 2008 at McLeans Creek.

The heavy oil wells primarily at Edam contributed 4% of annual funds from operations from 15% of total production. Operating netbacks of $8.33/BOE increased 10% compared to the prior year mainly due to a 9% increase in production compared to 2006.

Royalties

Year ended December 31	2007	2006
($000s)		
Crown	47,524	29,985
Freehold	1,149	1,134
GORR and other	2,913	1,781
Subtotal	**51,586**	32,900
ARTC and GCA	(10,033)	(9,371)
Net royalties	**41,553**	23,529
% of revenue	**21.0**	20.8
% of revenue net of ARTC and GCA	**16.9**	14.9

Gross royalties were 21.0% of revenues for 2007 compared to 20.8 % in 2006. By product, gross royalties were 18.8% for light oil, 23.79% for natural gas, 20.6% for heavy oil, and 26.48% for liquids. For 2006 by product, gross royalties were 13.1% for light oil, 26.1% for natural gas, 19.4% for heavy oil, and 32.7% for liquids. Average royalties in 2007 increased as a result of price increases per BOE as well as a reduction in royalty holidays mainly in the Puskwa area compared to 2006. In 2006 the average royalty rate in Puskwa was 11.73% and 21.18% in 2007. Net royalties of 16.9% increased due to a 57% increase in net royalties which was partially offset by a 7% increase in Gas Cost Allowance.

GORR royalties for 2007 increased by 64% compared to the prior year mainly due to encumbrances from the expansion of our Dawson Montney Gas and Eaglesham areas.

In 2006 Galleon received $500,000 of Alberta Royalty Tax credits (ARTC). For 2007 the ARTC program was discontinued.

Operating Costs

Year ended December 31	2007		
	Production %	Operating costs %	Operating costs $/BOE
Puskwa	**16**	**8**	**4.54**
Dawson Montney gas	**25**	**14**	**4.88**
Eaglesham	**13**	**9**	**5.82**
Dawson	**23**	**27**	**10.90**
Calais	**5**	**4**	**6.60**
Edam and other heavy oil	**15**	**32**	**21.23**
B.C.	**2**	**3**	**10.50**
Other	**1**	**3**	**20.31**
	100	**100**	**9.13**

Year ended December 31	2006		
	Production %	Operating costs %	Operating costs $/BOE
Puskwa	7	2	2.91
Dawson Montney gas	12	7	6.04
Eaglesham	3	2	(1.58)
Dawson	43	34	7.88
Calais	11	7	6.02
Edam and other heavy oil	20	42	21.93
B.C.	2	3	8.77
Other	2	3	17.04
	100	100	**9.85**

Operating costs were $44.8 million or $9.13/BOE for the year ended December 31, 2007 compared to $33.7 million or $9.85/BOE for the prior year. Galleon's operating costs per barrel of oil equivalent excluding the heavy oil were $7.01/BOE for the year and $6.88/BOE in 2006. Costs for the heavy oil assets decreased from $21.93/BOE in 2006 to $21.23/BOE in 2007 mainly due to increased production levels. Operating costs in Galleon's key areas of Puskwa, Dawson Montney gas, and Eaglesham remain low and below the corporate average for 2007 due to control of the facilities in those areas.

Operating costs for Puskwa increased to $4.54/BOE in 2007 compared to $2.91/BOE in 2006, mainly due to the waterflood project. This project resulted in an increase in water trucking costs of $0.30/BOE and pump rental costs of $0.55/BOE for water injection. Other cost increases for Puskwa were minor workover and well service costs of $0.70/BOE due to a greater percentage of pumping oil wells in 2007 compared to flowing wells in 2006. In 2008, operating costs are expected to decrease with the completion of permanent waterflood facilities. As well operating costs related to minor workovers and well servicing are expected to increase due to a larger number of pumping oil wells compared to the flowing oil wells in 2007.

Operating costs decreased to $4.88/BOE for Dawson Montney Gas compared to $6.04/BOE in 2006, due to control of the facilities in this area, increased production levels and increased processing revenues. In 2007, processing revenues from the facilities were $0.77/BOE compared to $0.49/BOE in 2006 and production of 3,406 BOE/day increased 204% compared to 1,120 BOE/day in 2006.

Eaglesham operating costs for 2007 were $5.82/BOE compared to ($1.58)/BOE in 2006. For 2006, processing revenues from the facilities were $7.15/BOE, while gross operating costs were $5.57/BOE.

Net operating costs therefore resulted in a credit of $1.58/BOE. Processing revenues in 2007 were $1.30/BOE and gross operating costs were $7.12/BOE. Operating costs for 2007 include trucking costs of $1.88/BOE and $1.29/BOE of third party processing and water disposal costs which will be eliminated in 2008 with the start up our Eaglesham oil battery.

Operating costs for the properties at Dawson of $10.90/BOE increased compared to $7.88/BOE in 2006, due to natural volume declines. Galleon's new discovery at McLeans Creek is a high netback oil producing property included in the Dawson area, but most of the production additions for 2007 were in the month of December 2007 and therefore did not contribute much to the operating cost per BOE for 2007.

The Eaglesham oil battery addition in the first quarter 2008, the anticipated expansion of natural gas facilities in the Dawson Montney gas to the capacity of 40 MMcf/d and other planned minor expansions to existing capacity at Galleon's facilities will sufficiently accommodate planned production increases. It is therefore anticipated that production additions in the key areas will be brought on stream at rates similar to or better than those experienced in 2007. It is anticipated that production increases in Galleon's key areas will lower the corporate average operating costs per barrel of oil equivalent.

General and Administration Expenses

Year ended December 31	2007		2006	
($000s)		$/BOE		$/BOE
Gross	12,155	2.48	9,926	2.90
Capitalized overhead	(3,775)	(0.77)	(3,592)	(1.05)
Overhead recoveries	(1,099)	(0.22)	(744)	(0.22)
	7,281	**1.49**	**5,590**	**1.63**

Net general and administrative (G&A) expenses of $1.49/BOE for 2007 were lower than the previous year as a result of increases in capital and operating overhead recoveries due to increases in capital spending and operating activity. Recoveries credited to operations were $1,098,913 and to capital were $3,775,829 in 2007 compared to $744,309 and $3,592,255 respectively in 2006. An amount of $1,035,950 was capitalized in 2007 (2006 - $660,500) for exploration salaries. Galleon's strategy of growth through asset acquisitions and drilling has enabled it to add production without significant increases to administrative costs. While gross G&A expenses have increased 22% with the growth of the Corporation, gross G&A expenses per barrel of oil equivalent have decreased by 14%. This is indicative of the efficiencies gained through production growth.

For the year ended December 31, 2007 G&A expenses by category were: salary and employee – 54%, office – 17%, audit, engineering and legal – 8%, consulting – 7%, computers – 6%, corporate – 6% and shareholder expense – 2%. In 2006 G&A expenses by category were: salary and employee – 51%, office – 15%, corporate – 10%, audit, engineering and legal – 9%, consulting – 10%, computers – 5%.

The Corporation will be relocating office space in April 2008 to accommodate current and planned growth resulting in an increase in G&A expenses in 2008.

Interest

Interest expense of $10.1 million for the year ended December 31, 2007 was higher compared to $4.5 million in the prior year due to increased average debt levels. The effective interest rate was 6.16% (2006 -5.38%). As at December 31, 2007 Galleon's debt to equity ratio of 0.33 provides flexibility to finance future capital programs, but has increased from 0.32 in the prior year. Galleon monitors its debt levels in relation to equity, and as a ratio of expected annual funds from operating activities. For 2008 interest costs are expected to increase due to higher average debt levels.

Stock Based Compensation

Stock based compensation was a non-cash expense of $8.5 million for the year compared to $7.7 million in the prior year. The increase was due to grants of options to new employees and an increase in the fair value of new options granted. As calculated by the Black-Scholes Option Pricing Model, all other factors being equal, an increase in Galleon's share price results in a higher option fair value. During the year 1,720,000 stock options were granted at an average exercise price of $15.51 and had fair values of between $4.14 and $5.62 per option.

At December 31, 2007 6,210,950 stock options were outstanding at an average exercise price of $12.36.

Depletion, Depreciation and Accretion

Depletion and depreciation charges were $100.3 million or $20.47/BOE for the year ended December 31, 2007 compared to $60.9 million or $17.81/BOE in the prior year.

Reserve additions for 2007 were estimated by an independent third party qualified reserves evaluator. Capital expenditures of $105.8 million ($76.5 million – December 31, 2006) related to undeveloped land, seismic, and equipment under construction have been excluded from the depletion and depreciation calculation and $110.8 million ($95.0 million – December 31, 2006) of future development costs have been added.

Accretion expense on the Corporation's asset retirement obligation was $1,948,696 for the year compared to $631,000 in the prior year. The increase related to a greater asset retirement obligation which was driven by the number of wells and facilities in which Galleon has an interest.

Capital and Future Taxes

The current tax provision of $879,358 for the year was comprised of Saskatchewan capital and resource taxes. The provision for future income taxes was $2.7 million for the year ended December 31, 2007 compared to $2.2 million for the prior year. The decrease in future taxes was a result of a decrease in both the federal and provincial income tax rates during the year and lower net earnings.

Galleon has estimated tax pools of $544.6 million as at December 31, 2007.

Capital Expenditures

($000s)	
Property & equipment balance at December 31, 2006	577,758
Additions to equipment inventory	293
Additions to property and equipment	208,344
Acquisition of property and equipment	52,082
Asset retirement obligation	4,326
Depletion and depreciation	(100,331)
Property & equipment balance at December 31, 2007	**742,472**

Year ended December 31	2007		2006	
($000s)		%		%
Land	10,789	5	31,385	11
Geological and geophysical	16,808	8	22,947	8
Drilling and completion	140,015	67	136,740	48
Plant and facilities	40,378	20	92,144	33
Other assets	354	-	132	-
Exploration and Development Expenditures	**208,344**	100	**283,348**	100

Capital expenditures during 2007 included $52.0 million for the acquisition of oil and gas properties in the Dawson, Kakut andShadow areas, and $208.3 million on exploration and development expenditures. In 2007 Galleon completed its most successful drilling program, 93 wells were drilled and 83 wells (74.8

net) were cased for an 89% success rate. By key area, 15 wells were drilled at Eaglesham, 12 wells were drilled at Puskwa, and 32 wells were drilled for Montney gas.

Land and seismic expenditures in 2007 were concentrated in the above three key areas. Management has established a capital budget of between $200 to $210 million for 2008 and plans to finance the program with funds from operating activities.

Liquidity and Capital Resources

Year ended December 31	2007	2006
($000s)		
Bank debt	**163,378**	122,996
Working capital deficiency	**30,179**	28,217
Total net debt	**193,557**	151,213

Funding of Capital Program

Year ended December 31	2007	2006
($000s)		
Issuance of shares, net of costs	88,332	168,208
Funds from operations	131,052	85,151
Change in bank debt	40,382	47,694
Change in working capital and other	(210)	9,120
	259,556	**310,173**

During the year, net proceeds of $88.3 million from equity offerings, funds from operations of $131.1 million, and an additional $40.2 million in bank debt and working capital were used to fund $259.6 million of acquisition and exploration and development expenditures.

At December 31, 2007, the Corporation has extendible revolving term credit facilities of $220 million in place with a bank syndicate. The facilities bear interest at rates ranging from the bank's prime rate to prime plus 0.75% per annum on $210 million and at rates ranging from the bank's prime rate plus 0.95% to prime plus 1.75% on $10 million based on the Corporation's debt to cash flow ratio. The Corporation may also borrow at the prevailing Banker's Acceptance rate. 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, 2007, an amount of $163.3 million was drawn against the credit facilities (December 31, 2006 - $123.0 million).

Subsequent to December 31, 2007 upon closing the acquisition of ExAlta Energy Inc., Galleon's extendible revolving term credit facility was increased to $265 million comprised of a lending facility of $250 million and an acquisition facility of $15 million.

Sensitivity Analysis

The following table shows sensitivities to funds from operations as a result of fluctuations to product prices, production volumes and other market factors. The table is based on budgeted 2008 prices and average production volumes of approximately 20,100 BOE/day.

Change to annual funds from operations	Change	$000s	$/share[2]
Price per barrel of oil (US$ WTI)[1]	$1.00	2,337	0.03
Price per Mcf of natural gas (C$ AECO)[1]	$0.25	4,491	0.07
Oil production volumes	100 bbl/d	1,824	0.03
Gas production volumes	1 MMcf/d	1,173	0.02
Exchange rate (US/Canadian)	$0.01	1,752	0.03
Interest rate on debt ($200 Million)	1%	2,000	0.03

[1] After adjustment for estimated royalties.

[2] Based on diluted shares outstanding at December 31, 2007.

Commitments

Drilling Rig:
The Corporation has entered into a Master Daywork Contract whereby it is entitled to the use of a drilling rig for a two year period which commenced November 15, 2007. Future minimum payments under this contract are as follows:

Year	Amount ($000s)
2008	2,344
2009	4,070

Equipment:
The Corporation has made installment payments of $482,940 related to equipment which will be delivered in the first quarter of 2008. The installment payments have been recorded on the balance sheet as prepaid. Additional future commitments for this equipment are $1.1 million.

Minimum Lease Payments:
At December 31, 2007 the Corporation has committed to future minimum payments under operating leases that cover office space as follows:

Year	Amount ($000s)
2008	2,333
2009	2,619
2010	1,768

The above commitment includes an estimate of the Corporation's share of operating expenses, utilities and taxes for the duration of the office lease.

Flow-through Shares:
In connection with the Corporation's flow-through share offerings in 2006, Galleon is obligated to spend $40.0 million on qualifying exploration expenses prior to December 2007. As at December 31, 2007, there are no remaining qualifying expenditures to be incurred.

In connection with the Corporation's flow-through share offerings in 2007, Galleon is obligated to spend $60.0 million on qualifying exploration expenses prior to December 31, 2008. As at December 31, 2007, $35.4 million of the required qualifying expenditures remains to be incurred.

Business Risks

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.

Galleon employs highly qualified people, uses sound operating and business practices, and evaluates all potential and existing wells using the latest applicable technology. Galleon complies with government regulations and has in place an up-to-date emergency response test. Environment and safety policies and standards are adhered to. Asset retirement obligations are recognized upon acquisition, construction, development and/or normal use of the assets. Galleon maintains property and liability insurance coverage. The coverage provides a reasonable amount of protection from risk of loss; however, not all risks are foreseeable or insurable.

Financial risks include fluctuations in commodity prices, interest rates and the Canadian/US dollar exchange rate. The Corporation currently has two financial contracts with a Canadian chartered bank and one term natural gas contract (see "Financial Instruments" for details). The Corporation also manages these risks by maintaining a healthy balance sheet with prudent levels of debt measured by debt to funds from operations and debt coverage ratios. This allows for strong financial capacity to maintain exploration and development activities in any downturn in commodity prices. 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.

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. In 2002, the Government of Canada ratified the Kyoto Protocol (the "Protocol"), which calls for Canada to reduce its greenhouse gas emissions to specified levels. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Protocol or as otherwise determined, 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.

Financial Instruments

As a means of managing the risk of commodity price volatility, Galleon has entered into two financial contracts with a Canadian chartered bank and one term natural gas contract. One crude oil costless collar contract is in place setting a floor price of CDN WTI $70.00/Bbl and a ceiling of CDN WTI $80.75/Bbl on 2,000 Bbl per day for the period January 1, 2008 to December 31, 2008. A second crude oil costless collar contract for 1,000 Bbl/day is in place setting a floor price of USD WTI $75.00/Bbl and a ceiling of USD WTI $100.00/Bbl for the period of January 1, 2008 to December 31, 2008. The contracts will protect base line revenues if the WTI crude oil benchmark falls below floor price. The contracts will be settled monthly based on the average USD and CDN WTI benchmark price. Galleon will receive payments on the contracts if the benchmark USD and CDN WTI price falls below the set floor price and will be required to make payments if the price rises above the set ceiling price. Galleon has recognized these financial instruments on its balance sheet at fair value, and is accounting for the instruments using mark to market accounting. As at December 31, 2007 Galleon has recorded an unrealized loss of $9.3 million based on a mark to market value related to these derivative instruments. The natural gas contract was put in place January 1, 2008 and is for 10,000 GJ/day for the period of February 1, 2008 to December 31, 2008 with pricing subject to a costless collar of $6.00/GJ and $8.00/GJ Canadian. These contracts are costless collars, therefore no premium was paid by Galleon upon entering into the contract.

Summary of Quarterly Results

Quarterly Highlights	2007			
	Q4	Q3	Q2	Q1
Financial ($000s)				
Revenues	71,339	60,156	60,734	52,974
Operating costs	(14,227)	(10,547)	(10,507)	(9,478)
General & Administrative expenses	(2,712)	(1,507)	(1,797)	(1,265)
Interest expense	(2,476)	(2,707)	(2,681)	(2,246)
Funds from operations[2]	**35,483**	**32,566**	**32,834**	**30,169**
Per share, basic[1,2]	0.56	0.54	0.55	0.52
Per share, diluted[1,2]	0.55	0.53	0.54	0.50
Earnings (loss)	**(495)**	**1,590**	**3,270**	**3,921**
Per share, basic[1]	(0.01)	0.03	0.06	0.07
Per share, diluted[1]	(0.01)	0.03	0.05	0.07
Total assets	**799,359**	**743,932**	**699,112**	**692,749**
Weighted average outstanding Class A shares-basic(1)	63,206,585	59,880,135	59,204,393	57,800,899
Weighted average outstanding Class A shares-diluted(1)	64,716,872	61,724,550	61,175,217	59,947,494

Quarterly Highlights	2006			
	Q4	Q3	Q2	Q1
Financial ($000s)				
Revenues	45,264	39,921	36,517	36,230
Operating costs	(9,651)	(9,243)	(7,716)	(7,065)
General & Administrative expenses	(2,670)	(692)	(1,068)	(1,160)
Interest expense	(1,487)	(1,202)	(1,098)	(740)
Funds from operations[2]	**23,857**	**21,178**	**22,069**	**18,047**
Per share, basic[1,2]	0.42	0.39	0.42	0.36
Per share, diluted[1,2]	0.40	0.37	0.40	0.35
Earnings	**1,906**	**2,196**	**7,985**	**1,740**
Per share, basic[1]	0.03	0.04	0.15	0.04
Per share, diluted[1]	0.03	0.04	0.15	0.03
Total assets	**614,565**	**540,980**	**477,967**	**399,269**
Weighted average outstanding Class A shares-basic(1)	56,761,415	54,854,334	52,003,462	49,661,598
Weighted average outstanding Class A shares-diluted(1)	59,234,229	57,447,555	54,838,259	52,220,178

[1]Restated to reflect a three-for-two Class A share split in June 2006.

[2]See "Non-GAAP Measurements".

During 2007 the quarterly increases in total assets compared to 2006 are a reflection of Galleon's capital expenditure program. Changes in revenues and funds from operations are primarily a function of Galleon's quarterly production volumes and commodity price changes.

Fourth Quarter Results

Three months ended December 31	2007		2006	
	1,351,986 BOE		999,982 BOE	
($000s)	$	$/BOE	$	$/BOE
Revenues	71,339	52.77	45,264	45.26
Royalties	(14,353)	(10.62)	(9,421)	(9.42)
ARTC and GCA	2,807	2.07	3,404	3.40
Transportation costs	(1,600)	(1.18)	(1,372)	(1.37)
Operating costs	(14,227)	(10.52)	(9,651)	(9.65)
Net	**43,966**	**32.52**	**28,224**	**28.22**
Other revenue	-	-	2	-
G&A	(2,712)	(2.00)	(2,670)	(2.67)
Interest costs	(2,476)	(1.83)	(1,487)	(1.49)
Realized loss on financial derivative	(3,367)	(2.49)	-	-
Capital and other taxes	72	0.05	(212)	(0.21)
Funds from operations	**35,483**	**26.25**	**23,857**	**23.85**

For the three months ended December 31, 2007 production by increased 35% to 14,695 BOE/d compared to 10,869 BOE/d in the same period of the prior year. Revenues were 58% higher as a result of commodity prices and greater production volumes. Average natural gas prices of $6.16/Mcf were 10% lower than $6.84/Mcf in Q4 2006. Average oil prices of $64.40/Bbl including oil hedges were 36% higher than $47.19/Bbl realized in Q4 2006.

The average light oil price received for Q4 2007 was $83.38/Bbl an increase of 32% compared to $63.03/Bbl in the prior year. The average heavy oil price in Q4 2007 of $37.32/Bbl increased by 20% compared to $31.16/Bbl in the prior year. For 2008, management has budgeted an average WTI price of USD $75.00 and average AECO price of $6.25/Mcf.

Operating costs were $14.2 million or $10.52/BOE for Q4 2007 compared to $9.7 million or $9.65/BOE for the prior year. Galleon's operating costs per barrel of oil equivalent excluding the heavy oil were $8.29/BOE for Q4 2007 and $6.12/BOE in Q4 2006. Operating cost increases in Q4 2007 consisted of: Edam ($0.28/BOE) field electrification; well services and minor workovers and trucking and processing costs at Eaglesham ($0.95/BOE) which will be eliminated in 2008 with the Eaglesham oil battery on production; and workovers in our Donnelly, Dreau and Kakut areas.

G&A expenses of $2,712,442 in Q4 2007 were 2% higher than Q4 2006. In Q4 2007 G&A expenses were $2.00/BOE, a decrease of 25% compared to $2.67/BOE in Q4 2006, which is indicative of the efficiencies gained through 35% growth in volumes year-over- year.

Performance by Property

Three months ended December 31	2007			2006			
	Production		Operating netbacks/ BOE [1]	Production		Operating netbacks/ BOE[1]	2007 Funds from operations2
	BOE/d	%	$	BOE/d	%	$	%
Puskwa	2,779	19	52.76	1,286	11	45.26	33
Dawson Montney gas	3,379	23	28.03	1,869	17	25.81	21
Eaglesham	2,005	14	27.85	845	8	39.42	13
Dawson	3,153	21	33.66	3,669	34	27.52	24
Calais	1,258	9	25.37	714	7	23.61	7
Edam and other heavy oil	1,746	12	2.39	2,100	19	1.07	1
B.C.	207	1	28.72	178	2	23.27	1
Other	168	1	12.15	208	2	26.57	-
	14,695	100	**30.45**	**10,869**	100	**24.82**	100

[1] Operating netbacks/BOE exclude ARTC and GCA and are calculated by subtracting royalties and operating costs from revenues divided by average production for the quarter.
2 See "Non-GAAP Measurements".

Production grew at Puskwa, Eaglesham and Dawson Montney Gas as the result of several high impact wells drilled during the year and due to successful development of these areas. The high deliverability wells are indicative of the quality of the reservoirs in these areas. Operating netbacks of $30.45/BOE in Q4 2007 increased by 23% compared to Q4 2006 of $24.82/BOE primarily as a result of higher netbacks in Galleon's key areas of Puskwa and Dawson Montney Gas. Production has increased by 104% in these key areas in Q4 2007 compared to Q4 2006. Operating costs in Galleon's key areas of Puskwa, Dawson Montney gas, and Eaglesham remain low and below the corporate average for 2007 due to control of the facilities in those areas and increased production. With the addition of Galleon's new light oil discoveries and reduced operating costs at Eaglesham, operating netbacks should continue to increase in 2008.

Critical Accounting Estimates

There are a number of critical estimates underlying the accounting policies employed in preparing the Corporation's 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 by an independent firm, Degoyler and McNaughton Canada Limited. 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.

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 Corporation 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 annually at year-end 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

Galleon adopted the following new Handbook Sections effective January 1, 2007:

- Section 1506, "Accounting Changes";
- Section 1530, "Comprehensive Income";
- Section 3251, "Equity";
- Section 3855, "Financial Instruments- Recognition and Measurement";
- Section 3861, "Financial Instruments- Disclosure and Presentation";
- Section 3865, "Hedges"

CICA Section 1506, "Accounting Changes," provides expanded disclosures for changes in accounting policies, accounting estimates and corrections of errors. Under the new standard, accounting changes should be applied retroactive unless otherwise permitted or where impracticable to determine. As well, voluntary changes in accounting policy are made only when required by a primary source of GAAP or the change results in more relevant and reliable information. There was no effect on the current or prior period financial statements as a result of this adoption.

CICA Section 1530, "Comprehensive Income", introduces a new requirement to temporarily present certain gains and losses from changes in fair value outside net income. It includes unrealized gains and losses, such as: changes in the currency translation adjustment relating to self-sustaining foreign operations; unrealized gains or losses on available-for-sale investments; and the effective portion of gains or losses on derivatives designated as cash flow hedges. The application of this revised standard did not result in comprehensive income being different from net earnings for the periods presented.

CICA Section 3251, "Equity", establishes standards for the presentation of equity and changes in equity during the reporting periods. The requirements of this section have been effected in the presentation of the Consolidated Statements of Changes in Shareholder' Equity. The application of this standard did not have a significant impact on Galleon's consolidated financial statements.

CICA Section 3855 "Financial Instruments – Recognition and Measurement" prescribes when a financial instrument is to be recognized on the balance sheet and at what amount. It also specifies how financial instrument gains and losses are to be presented. All financial instruments are classified into one of the following five categories: held for trading, held-to-maturity, loans and receivables, available-for-sale financial assets, or other financial liabilities. Initial and subsequent measurement and recognition of changes in the value of financial instruments depends on their initial classification. All derivative financial instruments are classified as held for trading financial instruments and are measured at fair value, even when they are part of a hedging relationship. All gains and losses are included in net earnings in the period in which they arise. The application of CICA Section 3855 does have an impact on Galleon's consolidated financial statements.

CICA Section 3865 provides alternative treatments to Section 3855 for entities which choose to designate qualifying transactions as hedges for accounting purposes. It replaces and expands on Accounting Guideline 13 "Hedging Relationships", and the hedging guidance in Section 1650 "Foreign Currency Translation" by specifying how hedge accounting is applied and what disclosures are necessary when it is applied. Galleon has not designated its financial derivative instrument as a hedge, therefore this section does not have an impact on Galleon's consolidated financial statements.

Future Accounting Policies

In addition, the Company has assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have a significant impact on the Company:

As of January 1, 2008, Galleon will be required to adopt two new CICA standards, Section 3862 "Financial Instruments – Disclosures" and Section 3863 "Financial Instruments – Presentation," which will replace Section 3861 "Financial Instruments – Disclosure and Presentation." The new disclosure standard increases the emphasis on the risks associated with both recognized and unrecognized financial instruments and how those risks are managed. The new presentation standard carries forward the former presentation requirements. The new financial instruments presentation and disclosure requirements were issued in December 2006 and the Company is assessing the impact on its consolidated financial statements.

As of January 1, 2008, Galleon will be required to adopt Section 1535 "Capital Disclosures," which will require companies to disclose their objectives, policies and processes for managing capital. In addition, disclosures are to include whether companies have complied with externally imposed capital requirements. The new capital disclosure requirements were issued in December 2006 and the Company is assessing the impact on its consolidated financial statements.

Galleon will be required to adopt Section 1400 "General Standards of Financial Statement Presentation", which was amended to include requirements to assess and disclose an entity's ability to continue as a going concern. The new requirements are effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2008. Galleon does not expect the adoption of this standard to have an impact on its financial statements.

As of January 1, 2008 Galleon will be required to adopt Section 3031 "Inventories" which replaces Section 3030, Inventories. The new standard is the Canadian equivalent to International Financial Reporting Standard IAS 2, Inventories. Section 3031 applies to interim and annual financial statements relating to fiscal years beginning on or after January 1, 2008. Galleon does not expect the adoption of this standard to have an impact on its financial statements.

Galleon will be required to adopt Section 3064 "Goodwill and Intangible Assets which will replace Section 3062 "Goodwill and Other Intangible Assets" and results in withdrawal of Section 3450, Research and Development Costs, and amendments to Accounting Guideline (AcG) 11, Enterprises in the Development Stage and CICA 1000, Financial Statement Concepts. The standard intends to reduce the differences with IFRS in the accounting for intangible assets as under current Canadian standards, more items are recognized as assets. The objectives of CICA 3064 are to reinforce the principle-based approach to the recognition of assets only in accordance with the definition of an asset and the criteria for asset recognition. The application of the concept of matching revenues and expenses is that the current practice of recognizing as assets items that do not meet the definition and recognition criteria is eliminated. The standard will also provide guidance for the recognition of internally developed intangible assets (including research and development activities), ensuring consistent treatment of all intangible assets, whether separately acquired or internally developed. These changes are effective for fiscal years beginning on or after October 1, 2008, with early adoption encouraged. Galleon is evaluating the effects of adopting this standard.

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 current 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. Companies will be required to provide comparative IFRS information for the previous fiscal year. Galleon's CEO and CFO are currently evaluating the impact of adopting IFRS.

Controls and Procedures over Financial Reporting

Galleon has established disclosure controls and procedures to provide reasonable assurance that material information relating to Galleon including its consolidated subsidiaries, is made known to the Chief Executive Officer (CEO) and the Chief Financial Officer (CFO) by others within those entities, particularly during the period in which the annual and interim filings are being prepared. The CEO and the 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.

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 material 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 the Corporation's most recent interim 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 for the respective year ends:

	2007	2006[1]
Class A shares outstanding		
Basic	63,215,552	57,712,077
Diluted[2]	69,426,502	63,022,402
Class B shares outstanding	922,500	922,500
Class A shares issuable on conversion of Class B shares[3]	595,161	510,232

[1]Restated to reflect a three-for-two Class A share split in June 2006.
[2] Includes outstanding options of 6,210,950 (December 31, 2006 – 5,310,325).
[3] Assumes a conversion based on the December 31, 2007 closing price of $15.50 per Class A share (December 31, 2006 -$18.08). The actual conversion rate varies based on a formula related to the trading price of the Class A shares.

At December 31, 2007, the market value of Galleon's class A and class B shares was $988.1 million based on the December 31, 2007 closing price of $15.50 per class A share and $8.91 per class B share. As of March 10, 2008, the number of class A shares, class B shares, and options outstanding are 67,769,274 922,500, and 6,382,084 respectively.

Additional Information

Additional information relating to the 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 2008, commodity prices have continued to strengthen and opportunities for consolidation acquisitions have increased. Galleon's focus is to create value through both drilling and acquisitions. Galleon plans to pursue acquisitions which have intrinsic value exceeding current market value and are accretive on a cash flow and reserve basis.

The acquisition of ExAlta Energy Inc. closed on January 16, 2008 which increased proved plus probable reserves by 5.3 million BOE to 64.8 million BOE, in aggregate.

The extendible revolving bank credit facility has been increased to $250 million with an additional $15 million acquisition facility.

Galleon has entered into an agreement to purchase a non-listed company ("Privateco") for consideration of $67.2 million which includes positive working capital of approximately $3.8 million. The acquisition price will be paid by the issuance of approximately 4 million Class A shares of Galleon. This is a consolidation acquisition with approximately 80% of the properties located in Galleon's Dawson Montney core area. The acquisition will add proved plus probable reserves of 4.2 million BOE and over 1,500 BOE/day of production (85% natural gas, 15% oil). In addition, 8 gas plants exceeding 42 Mmcf/d gross capacity and in excess of 65,000 net undeveloped acres of land will be acquired. The land and gas plants are estimated to be valued at $9.8 million. The acquisition will be completed by way of a plan of arrangement and is subject to receipt of approval by not less than 66 2/3% of the shareholders of Privateco that vote on the resolution, court approval and required regulatory approvals. The acquisition is expected to close prior to the end of May 2008.

With the strength of natural gas and light oil pricing, Galleon has positioned itself to explore and exploit more Montney natural gas resource plays and light oil projects which can deliver significant long life reserves and production.

Currently, one horizontal well in the Dawson Montney natural gas resource project is being drilled. The success of the horizontal well will affect positively the exploitation plan and increase potential reserves and production from the Dawson Montney gas project which contains over 500 sections of land.

In the second half of 2008, one horizontal and one vertical well in the Montney resource play located in B.C. are planned. One horizontal well, targeting the Montney resource play, in the Calais area of Alberta is also planned in the second half of 2008.

Sensitivity to the New Alberta Royalty Framework - Corporate total economic forecasts were rerun to examine the impact of the NRF. The government has not yet clarified certain aspects of the new royalty calculations. Accordingly, high and low sensitivities to the NRF were conducted using the Consultant's Consensus Methodology recommended by the Society of Petroleum Evaluation Engineers, Calgary Chapter. The "NRF High" scenario represents a more optimistic or high value sensitivity of the NRF impact and the "NRF Low" scenario represents the low value sensitivity. Based on currently available information, the net present value of net revenue of proved and probable reserves as at December 31, 2007, based on the NRF High scenario would be $933 million and based on the NRF Low scenario would be $921 million. The government has stated its intention to consult with industry and review the NRF for unintended consequences.

Quarterly Highlights	2007				2006			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production								
Light oil (Bbl/d)	4,419	3,375	3,317	3,127	2,419	1,823	1,753	1,859
Heavy oil (Bbl/d)	1,746	1,949	2,247	2,081	2,100	1,984	1,705	1,580
Natural Gas (Mcf/d)	49,486	48,989	45,314	38,845	36,733	33,068	30,014	30,445
Liquids (Bbl/d)	283	237	256	206	230	102	100	93
BOE/d	**14,695**	**13,726**	**13,372**	**11,888**	**10,869**	**9,420**	**8,560**	**8,606**
Total BOE produced	1,351,986	1,262,762	1,216,855	1,069,915	999,982	866,646	778,992	774,578
Daily BOE of production per million Class A shares - basic[1]	**232**	**229**	**226**	**206**	**191**	**172**	**165**	**173**
Prices (net of transportation)								
Light oil ($/Bbl)	83.38	78.43	70.12	63.24	63.03	75.65	75.63	65.66
Heavy oil ($/Bbl)	37.32	40.04	35.89	36.55	31.16	47.01	42.69	24.71
Crude oil ($/Bbl)	64.40	63.25	56.30	52.57	47.19	53.35	59.39	46.78
Natural Gas ($/Mcf)	6.16	5.73	7.14	7.36	6.84	5.58	5.97	7.36
NGLs ($/Bbl)	72.90	64.05	59.67	56.64	56.02	69.83	65.71	57.62
Per BOE ($)								
Revenues	52.77	47.64	49.91	49.51	45.26	46.06	46.88	46.77
Royalties, net of ARTC & GCA	(8.55)	(8.41)	(9.04)	(7.84)	(6.02)	(7.20)	(4.34)	(10.18)
Transportation costs	(1.18)	(1.13)	(1.16)	(1.47)	(1.37)	(1.25)	(1.22)	(1.43)
Operating costs	(10.52)	(8.35)	(8.63)	(8.86)	(9.65)	(10.66)	(9.91)	(9.12)
Net	**32.52**	**29.75**	**31.08**	**31.34**	**28.22**	**26.95**	**31.41**	**26.04**
Other revenue	-	-	-	-	-	-	-	-
G&A	(2.00)	(1.19)	(1.48)	(1.18)	(2.67)	(0.80)	(1.37)	(1.50)
Interest	(1.83)	(2.14)	(2.20)	(2.10)	(1.49)	(1.39)	(1.41)	(0.95)
Capital and other taxes	0.05	(0.18)	(0.41)	(0.21)	(0.21)	(0.33)	(0.30)	(0.29)
Realized gain (loss) on financial derivative	(2.49)	(0.44)	-	0.35				
Funds from operations[2]	**26.25**	**25.80**	**26.99**	**28.20**	**23.85**	**24.43**	**28.33**	**23.30**

[1]Restated to reflect a three-for-two Class A share split in June 2006.

[2]See "Non-GAAP Measurements"

END