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Calgary, Alberta T2P 0C1
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GALLEON ENERGY INC.

REVISED ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2006

June 25, 2007

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ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Mbbls	thousand barrels
MMbbls	million barrels
Mstb	1,000 stock tank barrels
Bbls/d	barrels per day
BOPD	barrels of oil per day
NGLs	natural gas liquids
STB	standard tank barrels

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMbtu	million British Thermal Units
Bcf	billion cubic feet
GJ	gigajoule
MM	Million

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.

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 2, 2007 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2006;

"**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

"**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 interest (operating and non-operating) share after deduction of royalties, plus the Corporation's royalty interest 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;

"**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, 2006.

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, results of Galleon's recent discovery at Puskwa, Alberta and the results of testing thereof, 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 by issuing one-half of one Class A Share for each Class A Share issued and outstanding. 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, 2006, Galleon did not have any material subsidiaries. Effective February 1, 2007 Galleon purchased a 99.9% interest in a partnership and the corporation holding the remaining 0.01% interest, for total cash consideration of $28.6 million. The partnership holds oil and gas assets within Galleon's core area of Dawson, Alberta.

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

History of the Corporation

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

2004

On January 15, 2004, Galleon announced the closing of the acquisition ("Venture Acquisition") of Venture. The purchase price was $17.75 million comprised of the issuance of 8,885,156 Class A Shares of Galleon at $1.80 per share and the assumption of $1.76 million of net debt. After giving effect to the acquisition, Galleon had 21,335,157 Class A Shares and 922,500 Class B Shares outstanding. Venture owned 750,000 of the Class A Shares which were cancelled on January 25, 2005. At the time of acquisition, Venture's production was 1.9 million cubic feet per day of natural gas (or 320 BOE).

On July 20, 2004 Galleon announced that it had entered into a farm-in agreement with a Canadian oil and gas company which allowed access to explore 328 gross sections (209,920 gross acres) of land in the Dawson area in the Peace River Arch region of Alberta. Galleon committed to drill a minimum of 28 wells on the farm-in lands over the next 24 months.

On July 28, 2004, Galleon completed the acquisition of Inisfail, a private company, for total consideration of $20.1 million. The acquisition was initially funded through an expanded credit facility. The purchase included 420 BOE/d of production (86% natural gas), strategic infrastructure with two natural gas plants, 42 miles of gas gathering systems and one crude oil battery. The acquired production was from two properties (Two Rivers and Flatrock) which are located in the greater Peace River Arch area.

On December 1, 2004, Galleon closed the purchase of oil and gas properties from an arm's length party for cash of $47 million including closing adjustments. The properties were located in Dawson, Alberta in the Peace River Arch region. The purchase included production of a minimum of 1,100 BOE/d (50% natural gas), strategic infrastructure with eight gas plants (average interest of 56%) and 91 miles of gas gathering systems, approximately 98,000 net acres of undeveloped land and significant upside for low risk development drilling, recompletions, and gas plant optimization.

During 2004 Galleon drilled 23.3 net natural gas wells and 0.6 net oil wells. The average production rate for the year was 1,581 BOE/day. Capital expenditures during 2004 were $53.2 million plus property acquisitions of $49.5 million.

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 a minimum of 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; significant upside for low risk development drilling and recompletions; 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 for gross proceeds of $55 million. In total, 3,405,000 Class A Shares were issued at $16.17 each.

On March 9, 2006, Galleon announced a major light sweet oil discovery in the Puskwa, Alberta area of the Peace River Arch. The discovery was made as part of a strategy to explore for high impact, big reserve base projects. The well (100% interest), located at 16-32-71-26W5M, was rig released on March 1, 2006. The well was drilled to a total depth of 10,354 feet and encountered 33 feet of oil pay with 14% weighted average porosity based on log analysis. The well flow tested at a rate of 2,559 BOE/d (90% oil and 10% gas) on a 10.32 mm choke. Reservoir drawdown was 10% during the test. The quality of the light sweet oil was 38° API.

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 12-11-72-26W5M, was drilled three miles from the 16-32 well with rig release on June 11, 2006. This well was drilled to a total depth of 10,187 feet and encountered 27 feet of oil pay in the Beaverhill Lake formation with porosity ranging from 9% to 20% based on log and core analysis. The well flow tested at a rate of 1,375 BOE/d (88% oil and 12% gas) on a 9.52mm choke. The quality of the light sweet oil was 38° API.

On July 25, 2006 Galleon closed a public offering of 2,985,000 Class A Shares at a price of $20.15 per Class A Share and 7,800 Class A Shares 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 16-11-72-26W5M, was drilled four miles from the first major well at 16-32 with rig release on August 26, 2006. This well was drilled to a total depth of 10,170 feet and encountered 20 feet of oil pay with porosity ranging from 12% to 21% based on log analysis. The well tested over a period of four days at a rate of 1,142 BOE/d (87% oil and 13% gas) with no water. The quality of the light sweet oil was 38° API.

On October 11, 2006, Galleon announced completion of its first horizontal and fifth major well at Puskwa, Alberta. The fifth well (50% interest), located 8-5-72-26W5M was rig released on October 5, 2006. This well was a re-entry and was drilled to a total measured depth of 9,393 and encountered 525 feet of horizontal oil pay in the Beaverhill Lake formation. The well tested at restricted rates exceeding 5,000 BOE/d (2,500 BOE/d net) (85% oil and 15% gas) with no water. To manage reservoir and reduce gas flaring the tests continued at restricted rates of 3,150 BOE/d (1,575 BOE/d net). The quality of the light sweet oil was 38° API.

On November 16, 2006, Galleon closed a public offering of 1,025,700 Class A Shares 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.

RECENT DEVELOPMENTS

On January 15, 2007, Galleon announced completion of the fourth horizontal well at Puskwa, Alberta. The well was a re-entry of a vertical well (100%), located at 11-10-72-26W5M, and was rig-released on December 25, 2006. The well was drilled to a total measured depth of 11,270 feet and encountered 731 feet of horizontal oil pay in the Beaverhill Lake formation. The well flowed during an initial test period of 60 hours, at an average rate of 650 BOE/d (88% oil and 12% gas). The quality of the light sweet oil was 38° API.

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

On February 5, 2007, Galleon announced completion of a vertical well (100%), located at 12-13-72-26W5M, which extended the northern border of the Puskwa light sweet oil pool adding approximately 2.5 sections (1,600 acres) of 100% Galleon land to the pool. The pool delineation is approximately two to three miles in width and five miles in length based on drilling results, geological and seismic interpretation.

On March 23, 2007 Galleon announced that it had entered into a financing agreement with an underwriting syndicate to issue on a "bought deal private placement basis" 1,481,500 Class A shares on a flow-through basis at $20.25 each for gross proceeds of $30,000,375. The issue is subject to normal regulatory approvals including approval of the Toronto Stock Exchange and closing is expected on or about April 19, 2007.

On March 23, 2007 Galleon was granted good production practice status by the EUB on section 32-71-26W5M and section 5-72-26W5M at Puskwa and will proceed with a pilot waterflood. Galleon plans to immediately pursue good production practice and waterflood expansion on its remaining developed sections at Puskwa.

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 north western Alberta. 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, 2006. 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 2, 2007. 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 constant prices and costs and 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.

All evaluations of future net production revenue set forth in the tables below are based on DeGolyer's pricing assumptions as at January 1, 2007 for the forecast case (December 31, 2006 for the constant case) 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 constant prices and costs assumptions and 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 (Constant Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2006
CONSTANT 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	3,543	2,693	2,147	1,823	31,311	23,095	149	100	11,058	8,465
Non-Producing	345	271	999	836	16,847	12,554	78	52	4,230	3,251
Proved Undeveloped	4,075	3,022	4,577	3,965	24,798	18,986	135	90	12,920	10,241
Total Proved	7,963	5,986	7,723	6,623	72,956	54,635	362	243	28,208	21,957
Probable	10,043	6,672	5,106	4,255	40,206	30,357	256	173	22,106	16,160
Total Proved plus Probable	18,006	12,658	12,829	10,879	113,162	84,992	618	416	50,314	38,117

NET PRESENT VALUES OF FUTURE NET REVENUE

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)
Proved Developed										
Producing	255,961	222,515	197,948	178,898	163,543	255,851	222,420	197,864	178,824	163,476
Non-producing	70,170	58,971	50,283	43,407	37,867	70,178	58,977	50,289	43,412	37,872
Proved Undeveloped	237,470	167,650	123,026	92,850	71,539	192,045	131,797	94,204	69,307	52,040
Total Proved	563,601	449,136	371,257	315,155	272,949	518,074	413,194	342,357	291,543	253,388
Probable	539,551	455,723	387,373	331,429	285,412	360,554	304,379	258,315	220,528	189,452
Total Proved plus Probable	1,103,152	904,859	758,630	646,584	558,361	878,628	717,573	600,672	512,071	442,840

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2006
CONSTANT 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	1,325	286	368	91	18	564	46	518
Total Proved plus Probable	2,452	600	587	141	21	1,103	225	879

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2006
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	192,379
	Heavy Oil (including solution gas and other by-products)	57,808
	Natural Gas (including by-products but excluding solution gas from oil wells)	121,070
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	485,904
	Heavy Oil (including solution gas and other by-products)	98,941
	Natural Gas (including by-products but excluding solution gas from oil wells)	173,784

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2006
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	3,540	2,693	2,121	1,800	31,738	24,415	150	101	11,101	8,663
Non-Producing	334	262	996	834	17,051	13,227	79	53	4,251	3,354
Proved Undeveloped	4,075	3,035	4,506	3,889	25,380	20,105	137	91	12,948	10,366
Total Proved	7,949	5,989	7,622	6,523	74,169	57,746	365	244	28,298	22,380
Probable	10,012	6,637	5,016	4,164	40,974	32,064	257	174	22,114	16,319
Total Proved plus Proabable	17,961	12,627	12,638	10,687	115,143	89,810	622	418	50,412	38,700

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)
Proved Developed										
Producing	307,210	267,779	238,832	216,365	198,209	307,120	267,702	238,764	216,305	198,154
Non-Producing	90,232	76,002	65,058	56,432	49,494	78,557	65,364	55,353	47,568	41,389
Proved Undeveloped	279,270	198,760	147,836	113,543	89,311	209,557	143,533	102,924	76,253	57,829
Total Proved	676,712	542,541	451,726	386,340	337,014	595,234	476,599	397,041	340,126	297,372
Probable	617,028	519,773	442,460	379,625	328,008	416,170	348,456	295,341	252,398	217,240
Total Proved plus Probable	1,293,740	1,062,314	894,186	765,965	665,022	1,011,404	825,055	692,382	592,524	514,612

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2006
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	1,535	313	430	95	22	677	82	595
Total Proved plus Probable	2,810	657	685	148	26	1,294	283	1,011

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2006
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	217,327
	Heavy Oil (including solution gas and other by-products)	59,949
	Natural Gas (including by-products but excluding solution gas from oil wells)	174,450
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	543,127
	Heavy Oil (including solution gas and other by-products)	102,016
	Natural Gas (including by-products but excluding solution gas from oil wells)	249,043

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 and constant 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 estimates are made) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are made). Reported total reserves estimated by deterministic or probabilistic methods, whether comprised of a single reserves entity or by an aggregate estimate for multiple entities, should target the following levels of certainty under a specific set of economic conditions:

(a) There is a 90 percent probability that at least the estimated proved reserves will be recovered; and

(b) There is a 50 percent probability that at least the sum of the estimated proved plus probable reserves will be recovered.

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 DeGolyer in the DeGolyer Report were DeGolyer's forecasts 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								
2007	65.00	75.12	44.34	7.32	76.62	54.84	0	0.862
2008	65.52	75.71	45.01	7.91	77.23	55.27	4	0.862
2009	64.27	74.26	45.21	7.72	75.74	54.21	3	0.862
2010	61.73	71.30	44.26	7.48	72.73	52.05	2	0.862
2011	59.07	68.20	43.15	7.68	69.57	49.79	2	0.862
2012	59.11	68.25	43.19	7.77	69.62	49.82	2	0.862
2013	60.29	69.62	44.21	7.92	71.01	50.82	2	0.862
2014	61.50	71.01	45.26	8.07	72.43	51.84	2	0.862
2015	62.73	72.43	46.32	8.22	73.88	52.87	2	0.862
2016	63.98	73.88	47.41	8.38	75.35	53.93	2	0.862
2017	65.26	75.35	48.52	8.59	76.86	55.01	2	0.862
2018	66.57	76.86	49.65	8.80	78.40	56.11	2	0.862
2019+	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.

4. Constant Cost and Price Assumptions

The constant crude oil and natural gas benchmark references pricing and the exchange rate utilized in the DeGolyer Report were as follows:

SUMMARY OF PRICING ASSUMPTIONS CONSTANT PRICES AND COSTS

				NATURAL GAS LIQUIDS		
Year	CRUDE OIL 40° API ($Cdn/Bbl)	HEAVY OIL 12° API Hardisty ($Cdn/Bbl)	NATURAL GAS AECO Gas Price ($Cdn/MMbtu)	Pentanes Plus FOB Field Gate ($Cdn/Bbl)	Butanes FOB Field Gate ($Cdn/Bbl)	Edmonton Propane FOB Filed Gate ($Cdn/Bbl)
2006 +	62.89	42.28	6.50	67.77	46.55	43.39

Weighted average historical prices realized by the Corporation for the year ended December 31, 2006, were $6.44/Mcf for natural gas, $68.81/Bbl for light crude oil and $36.75/Bbl for heavy oil.

5. Both the constant and 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.

Reconciliations of Changes in Reserves and Future Net Revenue

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

	LIGHT AND MEDIUM OIL			HEAVY OIL		
FACTORS	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)
December 31, 2005	1,354	658	2,012	7,170	4,484	11,654
Extensions	559	258	817	11	4	15
Improved Recovery	-	-	-	113	77	190
Technical Revisions	(101)	(241)	(342)	206	(389)	(183)
Discoveries	4,753	5,944	10,697	-	-	-
Acquisitions	47	35	82	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(18)	(16)	(34)	(409)	(12)	(421)
Production	(605)	-	(605)	(568)	-	(568)
December 31, 2006	5,989	6,637	12,627	6,523	4,164	10,687

	NATURAL GAS LIQUIDS			CONVENTIONAL NATURAL GAS			TOTAL		
FACTORS	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (MMcf)	Net Probable (MMcf)	Net Proved Plus Probable (MMcf)	Net Proved (MBOE)	Net Probable (MBOE)	Net Proved Plus Probable (MBOE)
December 31 2005	181	60	241	45,757	25,785	71,542	16,333	9,501	25,834
Extensions	100	23	123	26,867	9,306	36,173	5,149	1,835	6,984
Improved Recovery	-	-	-	-	-	-	113	77	190
Technical Revisions	(74)	(12)	(86)	(10,302)	(7,570)	(17,872)	(1,690)	(1,904)	(3,594)
Discoveries	73	103	176	3,022	4,221	7,243	5,330	6,750	12,080
Acquisitions	5	1	6	1,295	665	1,960	268	146	414
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	(1)	(1)	(2)	(355)	(343)	(698)	(487)	(85)	(572)
Production	(40)	-	(40)	(8,538)	-	(8,538)	(2,636)	-	(2,636)
December 31, 2006	244	174	418	57,746	32,064	89,810	22,380	16,319	38,700

RECONCILIATION OF CHANGES IN
NET PRESENT VALUES OF FUTURE NET REVENUE
DISCOUNTED AT 10% PER YEAR
PROVED RESERVES
CONSTANT PRICES AND COSTS

PERIOD AND FACTOR	(M$)
Estimated Future Net Revenue After Income Tax at December 31, 2005	252,410
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties	(95,349)
Net Change in Prices, Production Costs and Royalties Related to Future Production	(94,235)
Changes in Previously Estimated Development Costs Incurred During the Period	179,082
Changes in Estimated Future Development Costs	(197,359)
Extensions and Improved Recovery	85,337
Discoveries	154,429
Acquisitions of Reserves	7,018
Dispositions of Reserves	-
Net Change Resulting from Revisions in Quantity Estimates	(31,546)
Accretion of Discount	27,716
Net Change in Income Taxes	37,021
Other	17,833
Estimated Future Net Revenue After Income Tax at December 31, 2006	342,357

Notes:

(1) Except for "net change in income taxes" the changes disclosed above have been calculated on a pre-tax basis.

Additional Information Relating to Reserves Data

Undeveloped Reserves

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:

	Forecast Prices and Costs (M$)		Constant Prices and Costs (M$)
Year	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves
2007	37,213	55,270	37,145
2008	24,060	44,708	23,135
2009	10,463	14,245	9,768
2010	6,660	8,271	6,096
2011	4,644	6,845	4,167
Thereafter	11,918	18,892	10,270
Total Undiscounted	94,959	148,231	90,581
Total Discounted at 10%	78,189	122,109	75,230

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, 2006. Production stated is gross production to the Corporation and, unless otherwise stated, is average daily production during February 2007 based on field estimates. The reserve amounts stated are gross reserves, as at December 31, 2006 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 21W5M to 3W6M, and is approximately 25 miles northeast of Grande Prairie, Alberta. Calais consists of the Puskwa, Eaglesham, Kakut, Peoria, and Rycroft areas.

The Puskwa property is located in Townships 71 to 73, and Ranges 25W5M to 1W6M. Galleon is the operator of the wells and facilities, with a 96% average working interest in the 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 25W5M to 1W6M. Galleon is the operator of the wells and facilities, with an average working interest in the wells of approximately 65%. 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. Aproximately 85% of this area has year round access for drilling, seismic and construction projects.

During 2006 Galleon drilled 31 (25.3) net wells and cased 29 (27.6 net) wells at Calais. Galleon plans to drill 35 wells in 2007. At December 31, 2006, there were 45 (30.9 net) wells on production and 44 (33.1 net) suspended or standing. February 2007 production was approximately 9.4 MMcf/d and 1,701 Bbls/d of oil and NGLs, based upon field estimates. At February 12, 2007, the Corporation had an interest in 69,476 gross acres (50,310 net acres) of undeveloped land in the Calais area.

The DeGolyer Report assigns total proved reserves of 7.4 MMbbls of oil and NGLs and 17.2 Bcf of natural gas, and total proved plus probable reserves of 17.1 MMbbls of oil and NGLs and 30.7 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. During the first half of 2005, Galleon acquired oil and gas assets in this area. 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, McLean Creek and Gage.

The Dawson Montney gas play is located in Townships 75 to 78 and Ranges 19 to 21W5M. 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 850 meters depth. This zone lies within the Triassic age Montney formation. All of this area has year round access for drilling, seismic and construction projects.

The average working interest in the Dawson area is approximately 82%. 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 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 2006 Galleon drilled 76 (63.7 net) wells and cased 67 (56.7 net) wells at Dawson. Galleon plans to drill 70 wells in 2007. At December 31, 2006, there were 138 (113.5 net) wells on production at Dawson and 172 (161.4 net) non-producing wells. February 2007 production was approximately 27.7 MMcf/d and 1,393 Bbls/d of oil and NGLs, based on field estimates. At February 12, 2007, the Corporation had interest in 461,614 gross acres (377,392 net acres) of undeveloped land.

The DeGolyer Report assigns total proved reserves of 0.9 MMbbls of oil and liquids and 52.7 Bcf of natural gas, and total proved plus probable reserves of 1.5 MMbbls of oil and liquids and 76.2 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 has a 100% working interest. 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 2006 Galleon drilled 6 (6.0 net) wells and cased 6 (6.0 net) wells for oil production at Edam. At December 31, 2006, there were 41 (41 net) wells on production, and 23 (23 net) standing or suspended wells at Edam. February 2007 production was approximately 1,826 Bbls/d of oil, based upon field estimates. At February 12, 2007, the Corporation had an interest in 17,586 gross acres (17,586 net acres) of undeveloped land at Edam.

The DeGolyer Report assigns total proved reserves of 7.3 MMbbls of oil, and total proved plus probable reserves of 12.1 MMbbls.

Minor Properties

Wymark, Saskatchewan

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

In February 2007, the property was producing approximately 0.7 MMcf/d from 27 wells based on field estimates. At February 12, 2007, the Corporation had an interest in 5,923 gross acres (5,923 net acres) of undeveloped land. There are no current plans to drill wells at Wymark in 2007.

The DeGolyer Report assigns total proved reserves of 2.0 Bcf of natural gas and total proved plus probable reserves of 3.4 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 82 %working interest. The properties produce natural gas, crude oil and NGLs.

At February 12, 2007 the Corporation had an interest in 11,543 gross acres (9,455 net acres) of undeveloped land.

The DeGolyer Report assigns total proved reserves of 1.5 Bcf of natural gas and 106 Mbbls of crude oil and NGLs and total proved plus probable reserves of 3.8 Bcf of natural gas and 129 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, John Lake, Monitor, Wainwright, Karr, Princess and Progress, Alberta. In aggregate, total proved reserves of 0.8 Bcf of natural gas and 195 Mbbls of crude oil and NGLs and total proved plus probable reserves of 1.1 Bcf of natural gas and 314 Mbbls of oil and NGLs. The Corporation has no current plans to drill on these properties in 2007. Galleon has interests in approximately 18,781 gross acres (13,151 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, 2006.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	95	60.6	84	54.6	117	91.3	251	207.2
British Columbia	5	2.6	4	2.0	4	2.6	28	14.9
Saskatchewan	59	53.5	74	67.5	30	29.0	11	11.0
Total	159	116.7	162	124.1	151	122.9	290	233.1

Properties with no Attributable Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2006.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	201,369	150,288	603,621	483,147	804,990	633,435
British Columbia	17,142	9,533	11,543	9,455	28,685	18,988
Saskatchewan	21,307	19,511	28,237	26,375	49,544	45,886
Total	239,818	179,332	643,401	518,977	883,219	698,309

The Corporation expects that rights to explore, develop and exploit 29,230 net acres of its undeveloped land holdings will expire by December 31, 2007, 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:		
November 1, 2006 – March 31, 2007	5,000 GJ/day	CDN $7.51 GJ
February 2007	5,000 GJ/day	CDN $7.00 GJ
February 2007	5,000 GJ/day	CDN $7.25 GJ
February 2007	5,000 GJ/day	CDN $7.50 GJ
March 2007	5,000 GJ/day	CDN $7.02 GJ
March 2007	5,000 GJ/day	CDN $7.26 GJ
March 2007	5,000 GJ/day	CDN $7.50 GJ
April 1, 2007 – October 31, 2007	5,000 GJ/day	CDN $6.64 GJ
April 1, 2007 – October 31, 2007	5,000 GJ/day	CDN $6.50 - $8.12 GJ
April 1, 2007 – October 31, 2007	5,000 GJ/day	CDN $7.50 GJ

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

Crude Oil:		
January 1, 2007 – December 31, 2007	1,000 Bbl/d	WTI USD $61.75-$70.00/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 543 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 (M$)

Year	Total Proved Abandonment Costs (Undiscounted)	Total Proved plus Probable Abandonment Costs (Undiscounted)
2007	539	385
2008	1,860	1,253
2009	5,763	5,392
Thereafter	13,867	19,323
Total Undiscounted	22,029	26,353
Total Discounted @ 10%	11,820	12,301

Constant Prices and Costs (M$)

Year	Total Proved Abandonment Costs (Undiscounted)	Total Proved plus Probable Abandonment Costs (Undiscounted)
2007	605	396
2008	1,663	1,249
2009	5,425	4,992
Thereafter	10,756	14,861
Total Undiscounted	18,449	21,498
Total Discounted @ 10%	10,589	10,823

Tax Horizon

The Corporation does not expect to pay current income tax for the 2007 fiscal year. Depending on production, commodity prices and capital spending levels, the Corporation may begin paying current income taxes in 2008.

Capital Expenditures

The following table summarizes capital expenditures related to the Corporation's activities for the year ended December 31, 2006:

	(M$)
Property acquisition costs	
Proved properties	25,396
Undeveloped properties	31,385
Exploration costs	64,919
Development costs	187,044
Dispositions	-
Total	308,744

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, 2006:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Light and Medium Oil	5	3.3	23	18.8
Heavy Oil	-	-	6	6.0
Natural Gas	27	23.5	45	36.4
Dry	10	9.8	2	1.6
Total	42	36.6	76	62.8

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 2006, 11 wells were drilled at Puskwa, 8 at Eaglesham, and 50 Montney gas wells at Dawson. The majority of capital expenditures in 2007 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 2007 in the estimates of future net revenue from proved and proved plus probable reserves disclosed under "Disclosure of Reserves Data and Other Information".

From Proved reserves:	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)	%
Dawson	710	-	17,123	14	3,578	28
Edam and other heavy oil	2	2,281	-	-	2,283	18
Puskwa	1,939	-	1,312	33	2,191	17
Dawson Montney gas	42	51	11,474	34	2,039	16
Eaglesham	444	-	5,626	64	1,446	11
Other	82	67	6,228	26	1,213	10
Total	3,219	2,399	41,763	171	12,750	100

From Proved plus Probable reserves:	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)	%
Dawson	871	-	17,123	14	3,578	24
Edam and other heavy oil	2	2,888	-	-	2,890	19
Puskwa	2,477	-	1,660	41	2,795	19
Dawson Montney gas	47	56	12,638	36	2,245	15
Eaglesham	498	-	6,458	74	1,648	11
Other	91	75	9,099	30	1,874	12
Total	3,986	3,019	46,978	195	15,030	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			
	2006			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production[1]				
Light and Medium Crude Oil (Bbls/d)	2,419	1,823	1,753	1,859
Heavy Oil (Bbls/d)	2,100	1,984	1,705	1,580
Gas (Mcf/d)	36,733	33,068	30,014	30,445
NGLs (Bbls/d)	230	102	100	93
Combined (BOE/d)	10,869	9,420	8,560	8,606
Average Price Received (net of transportation)				
Light and Medium Crude Oil ($/Bbl)	61.12	75.65	75.63	65.66
Heavy Oil ($/Bbls)	31.16	47.01	42.69	24.71
Gas ($/Mcf)	6.84	5.58	5.97	7.36
NGLs ($/Bbls)	56.02	69.83	65.71	57.62
Combined ($/BOE)	43.89	44.81	45.66	45.34
Royalties Paid				
Light and Medium Crude Oil ($/Bbls)	9.71	7.47	4.69	13.48
Heavy Oil ($/Bbls)	5.72	9.96	8.76	4.12
Gas ($/Mcf)	0.71	0.97	0.38	1.79
NGLs ($/Bbls)	16.38	24.85	25.56	17.49
Combined ($/BOE)	6.02	7.20	4.34	10.18
Operating Expenses ($/BOE)				
Light and Medium Crude Oil ($/Bbls)	9.37	9.71	11.00	10.65
Heavy Oil ($/Bbls)	24.38	22.88	19.93	19.62
Gas ($/Mcf)	0.85	1.13	1.05	0.91
NGLs ($/Bbls)	-	-	-	-
Combined ($/BOE)	9.65	10.66	9.91	9.12
Netback Received ($/BOE)[2]				
Light and Medium Crude Oil ($/Bbls)	42.04	58.47	59.94	41.53
Heavy Oil ($/Bbls)	1.06	14.17	14.00	0.97
Gas ($/Mcf)	5.28	3.48	4.54	4.66
NGLs ($/Bbls)	39.64	44.98	40.15	40.13
Combined ($/BOE)	28.22	26.95	31.41	26.04

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, 2006:

	Light and Medium Crude Oil (Bbls/d)	Heavy Oil (Bbls/d)	Gas (Mcf/d)	NGLS (Bbls/d)	BOE (BOE/d)
Puskwa	597	-	308	9	657
Dawson Montney gas	29	-	6,416	22	1,120
Eaglesham	64	-	1,196	16	280
Dawson	1,102	-	17,239	34	4,010
Calais	107	-	5,128	40	1,002
Edam and other heavy oil	-	1,845	3	-	1,846
Other	64	-	2,294	10	455
Total	1,963	1,845	32,584	131	9,370

The Corporation's crude oil production for the year ended December 31, 2006 was 21% light quality crude oil (32° API or greater), 20% heavy oil, 58% natural gas, and 1% liquids.

For the twelve months ended December 31, 2006, approximately 48% of the Corporation's gross revenue was derived from crude oil production and 52% 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 were listed and posted for trading on the TSX Venture Exchange until September 5, 2006 at which time they commenced 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 exchanges) 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)
2006						
January	17.93	15.71	2,973,696	8.60	8.00	14,900
February	16.79	12.83	3,749,978	9.00	8.20	8,860
March	23.50	13.40	8,717,601	9.50	8.11	49,140
April	25.00	21.50	3,431,907	8.41	7.75	28,350
May	24.00	19.83	4,977,333	8.25	7.90	10,800
June(1)	22.03	17.70	4,599,953	8.10	8.00	13,030
July	22.70	18.80	3,624,988	8.25	8.00	11,300
August	22.17	18.65	2,450,020	8.10	8.10	1,000
September	19.95	16.65	2,817,902	8.29	8.29	6,600
October	21.15	16.55	3,830,126	8.12	8.12	1,475
November	20.10	17.25	3,639,279	8.60	8.15	3,950
December	18.85	16.47	5,484,916	8.80	8.40	4,500
2007						
January	18.25	14.25	7,458,110	8.50	8.50	22,250
February	17.76	15.77	6,373,250	8.50	8.50	8,500
March (1-26)	17.15	14.46	6,118,721	8.98	8.52	7,250

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	President, Menehune Resources Ltd. (private oil and gas company)	May 16, 2003
William L. Cooke[1][3] Magna Bay, British Columbia, Canada	Director	Independent Businessman	May 16, 2003
Brad R. Munro[1][5] Saskatoon, Saskatchewan, Canada	Director	Vice President, Investments of Growthworks Capital Ltd. and affiliates and Manager of Growth Works Canadian Fund Inc. (public investment company)	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
Thomas J. Greschner Cochrane, Alberta, Canada	Vice-President, Production	Vice-President, Production of the Corporation	N/A
C. Brent Lacey Calgary, Alberta, Canada	Vice-President, Exploration	Vice-President, Exploration of the Corporation	N/A
Dale Orton Calgary, Alberta, Canada	Vice-President, Engineering West	Vice-President, Engineering West of the Corporation	N/A
Devin K. Sundstrom Calgary, Alberta, Canada	Vice-President, Engineering East	Vice-President, Engineering East 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".

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

As at March 26, 2007, the directors and officers of Galleon and their associates, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, 5,339,443 Class A Shares and 59,590 Class B Shares or approximately 9% of the issued and outstanding Class A Shares and 7% 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 29 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. He is currently President of Selinger Capital Inc., a private investment company. Mr. Carley was also Chairman and Chief Executive Officer of New Venture Energy Inc., a private oil and gas company from December 2004. 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 22 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 26 years. Ms. Crabtree is also currently Vice President, Finance of Culane Energy Corp. 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.

Thomas J. Greschner, Vice-President, Production

Mr. Greschner has 21 years of oil and gas production, operations, facility/pipeline construction and safety/environment experience. Most recently, Mr. Greschner was the Production Manager for KeyWest Energy Corporation/Viking Energy Trust and prior thereto, held positions of increasing responsibility at Husky Energy Inc., Renaissance Energy Ltd., and Petro-Canada Oil and Gas.

C. Brent Lacey, Vice-President, Exploration

Mr. Lacey is a professional geologist with 20 years industry experience, 11 of which has been in exploration, development and property acquisition in the Western Canadian Sedimentary Basin.

Mr. Lacey was employed as Senior Geologist at KeyWest Energy Corporation, Newport Petroleum Corp., Stampeder Exploration Ltd., Rigel Oil & Gas Ltd. and Inverness Petroleum Ltd. Mr. Lacey's career in the industry has mainly been in the role of lead oil and gas prospect generator. Over the previous 2-3 years, he was an integral part of the exploration and development growth at KeyWest.

Mr. Lacey hold a Bachelor of Science degree from the University of Saskatchewan and is registered as a Professional Geologist in the provinces of Alberta and Saskatchewan.

Dale Orton, Vice-President, Engineering West

Mr. Orton is a professional engineer with 13 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, Engineering East

Mr. Sundstrom is a professional engineer with 13 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.

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 also a director of Okanagan University College. 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 President of Menehune Resources Ltd., a private oil and gas 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 Vice President, Investments of GrowthWorks Capital Ltd. and affiliates, and Manager of GrowthWorks Canadian Fund Inc. Mr. Munro is also an officer of GrowthWorks Capital Ltd. and of GrowthWorks WV Management Ltd. Mr. Munro has been employed with GrowthWorks and its affiliates since September 1991. Mr. Munro holds a Bachelor of Commerce degree and has 14 years experience where his responsibilities included sourcing, analyzing, and the placement and management of investments for the fund. Mr. Munro has served on the audit committee of 16 of the Boards that he has been involved with and presently serves on the audit committees of five private companies and four public companies, including CCS Inc., Fairmont Energy Inc., Galleon Energy Inc. and Flagship Energy Inc.

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 $165,000 in 2006 and $124,500 in 2005.

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 $89,500 in 2006 and $43,800 in 2005. 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 $9,000 in 2006 and $17,500 in 2005. Fees were billed for services provided in the preparation of corporate tax returns.

All Other Fees

No fees were billed in either of the last two fiscal years for products and services provided by the Corporation's auditors other than services reported above.

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, 2006, Galleon employed 41 full-time employees located in the head office, and 6 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 to which the Corporation is a party or of which any of their respective properties is the subject matter nor are there any such proceedings known to the Corporation to be contemplated.

During the year ended December 31, 2006 there were no penalties or sanctions imposed against the Corporation or by a court relating to securities legislation or by a securities regulatory authority. In addition, there were (i) no other penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision, and (ii) no settlement agreements the Corporation 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, directly or indirectly, or exercises control or direction over more than 10% of the outstanding Common Shares, or any other Informed Person (as defined in National Instrument 51-102) or any known associate or affiliate of such persons, in any transaction since the commencement of the last completed financial year of the Corporation or in any proposed transaction which has materially affected or would materially affect the Corporation or any of its subsidiaries except as follows.

On February 14, 2006, Mr. Carley, Mr. Sugianto and Ms. Crabtree purchased pursuant to a private placement 60,000, 3,000 and 7,500, respectively, Class A Shares at an issue price of $16.17 per share which was on the same basis as other arm's length subscribers to such offering.

On November 16, 2006, Mr. Sugianto, Ms. Crabtree, Mr. Lacey and Mr. Greschner purchased pursuant to a prospectus 3,000, 2,000, 2,000 and 4,000, respectively, Class A Shares issued on a "flow-through" basis at an issue price of $25.00 per share which was on the same basis as other arm's length subscribers to such offering.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Corporation has not 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.

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 and Ernst & Young LLP, the Corporation'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. 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 market, 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 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 2006 Federal Budget, the federal corporate income tax rate will decrease to 19% in three steps: 20.5% on January 1, 2008, 20% on January 1, 2009 and 19% on January 1, 2010.

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, 2007, 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 is May 31, 2007.

On February 16, 2007, the Alberta Government announced that a review of the province's royalty and tax regime (including income tax and freehold mineral rights tax) pertaining to oil, gas and oil sands will be conducted by a panel of experts, with the assistance of individual Albertans and key stakeholders. The purpose of this process is to ensure that Albertans are receiving a fair share from energy development through royalties, taxes and fees. The issues to be reviewed during this examination process are: (i) undertaking a comparison of Alberta's royalty system to other oil and gas producing jurisdictions, taking into account investment economics and industry returns and risks in Alberta; (ii) whether Alberta's royalty system is sufficiently sensitive to market conditions; (iii) whether the current revenue minus cost system for oil sands royalties is optimal; (iv) which programs built into the existing royalty system should be retained or strengthened, and which should be adapted or eliminated; (v) how the tax treatment of the oil and gas sector compares to other sectors and jurisdictions; (vi) the economic and fiscal impacts of any possible changes to the royalty and corporate tax structures; and (vii) how existing resource development should be treated if changes are to be made to the fiscal regime. The review panel is to produce a final report that will be presented to the Minister of Finance by August, 31, 2007.

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.

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. 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 establishing 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.

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. 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.

- 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.

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 five years since the federal government had the initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income.

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. No additional expenses are foreseen that are associated with complying with the new regulations. 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.

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.

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 remains uncertain whether the Kyoto target of 6% below 1990 emission levels will be enforced in Canada. The Federal Government has introduced legislation aimed at reducing greenhouse gas emissions using a "intensity based" approach, the specifics of which have yet to be determined. 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. As details of the implementation of this legislation have not yet been announced, the effect on the Corporations' operations cannot be determined at this time.

Trends

There are a number of trends that have been developing in the oil and gas industry during the past several years that appear to be shaping the near future of the business.

The first trend is the volatility of commodity prices. Natural gas is a commodity influenced by factors within North America. A tight supply-demand balance for natural gas causes significant elasticity in pricing, whereas higher than average storage levels tend to depress natural gas pricing. Drilling activity, weather, fuel switching and demand for electrical generation are all factors that affect the supply-demand balance. Changes to any of these or other factors create price volatility.

Crude oil is influenced by the world economy, Organization of the Petroleum Exporting Countries' ability to adjust supply to world demand and weather. Crude oil prices have been kept high by political events causing disruptions in the supply of oil and concern over potential supply disruptions triggered by unrest in the Middle East and more recently have been impacted by weather and increased storage levels. Political events trigger large fluctuations in price levels.

The impact on the oil and gas industry from commodity price volatility is significant. During periods of high prices, producers generate sufficient cash flows to conduct active exploration programs without external capital. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services. Purchasing land and properties similarly increase in price during these periods. During low commodity price periods, acquisition costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers also decline.

A second trend within the Canadian oil and gas industry is the fairly consistent "renewal" of private and small junior oil and gas companies starting up business. These companies often have experienced management teams from previous industry organizations that have disappeared as a part of the ongoing industry consolidation. Many are able to raise capital and recruit well qualified personnel. The Corporation will have to compete with these companies and others to attract qualified personnel.

A third trend currently affecting the oil and gas industry is the impact on capital markets caused by investor uncertainty in the North American economy. The capital market volatility in Canada has also been affected by uncertainties surrounding the economic impact that the Protocol, and other environmental initiatives, will have on the sector and, in more recent times, by the October 31, 2006 proposals of the Federal government of Canada (the "October 31, 2006 Proposals") relating to income trusts and other "specified investment flow-through" entities ("SIFTs"). Pursuant to the existing provisions of the *Income Tax Act* (Canada), to the extent that a SIFT has any income for a taxation year after certain inclusions and deductions, the SIFT will be permitted to deduct all amounts of income which are paid or become payable by it to unitholders in the year. Under the October 31, 2006 Proposals, SIFTs will be liable for tax at a rate consistent with the taxes currently imposed on corporations commencing in January 2011, provided that the SIFT experiences only "normal growth" and no "undue expansion" before then, in which case the tax could be imposed prior to the January 2011 deadline. Although the October 31, 2006 Proposals will not affect the method in which the Corporation will be taxed, they may have an impact on the ability of a SIFT to purchase producing assets from junior oil and gas companies (as well as the price that a SIFT is willing to pay for such an acquisition) thereby affecting exploration and production companies' ability to be sold to a SIFT which has been a key "exit strategy" in recent years for small to mid-sized oil and gas companies. This may be a benefit for the Corporation as it will compete with SIFTs for the acquisition of oil and gas properties from junior producers. However, it may also limit the Corporation's ability to sell producing properties or pursue an exit strategy.

Generally during the past year, the economic recovery combined with increased commodity prices has caused an increase in new equity financings in the oil and gas industry, although the level of same was negatively impacted by the October 31, 2006 Proposals. The Corporation will compete with numerous new companies and their new management teams and development plans in its access to capital. The competitive nature of the oil and gas industry will cause opportunities for equity financings to be selective. The Corporation may have to rely on internally generated funds to conduct their exploration and developmental programs.

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.

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.

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.

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.

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. At this time the Alberta Government is in the process of examining the royalty and tax regime applicable to oil, gas and oil sands – see "Industry Conditions – Provincial Royalties and Incentives". 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.

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 which will likely subject the Corporation to possible future legislation regulating emissions of greenhouse gases. The Government of Canada has proposed a Bill, which suggests further legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas exploration and production. Future federal legislation, together with provincial emission reduction requirements, such as those included in Alberta's Climate Change and Emissions Management Act (partially in force), may require the reduction of emissions (or emissions intensity) produced by the Corporation's expected operations and facilities. 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 either the nature of those requirements or the impact on the Corporation and its operations and financial condition. See "Industry Conditions – Environmental Regulation".

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 Corporation's revenues, profitability and future growth and the carrying value of its oil and gas properties are substantially dependent on prevailing prices of oil and gas. The Corporation's ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. 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, 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.

The exchange rate between the Canadian and U.S. dollar also affects the profitability of the Corporation and the Canadian dollar has strengthened recently against the U.S. dollar.

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 in part 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.

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 favourable 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.

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..

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 both constant and 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.

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.

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.

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.

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.

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.

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

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 *Business Corporations Act* (Alberta) (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.

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.

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 consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at December 31, 2006 using constant prices and costs; and

(ii) the related estimated future net revenue.

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 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.

DATED as of this 13th day of March, 2007.

(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, 2006. The reserves data consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) proved oil and gas reserves estimated as at December 31, 2006 using constant prices and costs; and

   (ii) the related estimated future net revenue.

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, 2006, 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, 2006 on Certain Properties owned by Galleon Energy Inc. dated March 2, 2007	Canada	-	894,186	-	894,186

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.

EXECUTED as to our report referred to above.

DeGolyer and MacNaughton Canada Limited, Calgary, Alberta, dated March 2, 2007.

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.

GALLEON
ENERGY INC.

Financial Statements

DECEMBER 31, 2006

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.

Steve Sugianto
President and Chief Executive Officer
March 13, 2007

Shivon M. Crabtree
Vice President Finance and
Chief Financial Officer

AUDITORS' REPORT

To the Shareholders of Galleon Energy Inc.

We have audited the balance sheets of Galleon Energy Inc. as at December 31, 2006 and 2005 and the statements of earnings 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 financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst + Young LLP

Calgary, Canada
March 13, 2007

Chartered Accountants

GALLEON ENERGY INC.
Balance Sheets
As at December 31

($000s)	2006	2005
ASSETS		
CURRENT		
Accounts receivable	24,639	23,234
Deposits and prepaid expenses	1,839	961
Fair value of financial derivative (note 8)	190	-
	26,668	24,195
Goodwill	10,139	10,139
Property and equipment (notes 2 and 4)	577,758	318,285
	614,565	**352,619**
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	54,695	42,677
Bank loan (note 4)	122,996	75,301
	177,691	117,978
Asset retirement obligation (note 3)	21,432	11,186
Future income taxes (note 6)	32,287	26,395
	231,410	155,559
SHAREHOLDERS' EQUITY		
Share capital (note 5)	339,869	174,463
Contributed surplus (note 5)	11,619	4,756
Retained earnings	31,667	17,841
	383,155	197,060
	614,565	**352,619**

See accompanying notes

Approved on behalf of the Board of Directors:

"Signed"

William L. Cooke

Director

"Signed"

Fred C. Coles

Director

GALLEON ENERGY INC
Statements of Earnings and Retained Earnings
Years ended December 31

($000s, except per share amounts)	2006	2005
REVENUE		
Petroleum and natural gas revenue	157,931	135,050
Royalties, net of ARTC and GCA	(23,529)	(29,805)
Other income	5	25
	134,407	105,270
EXPENSES		
Operating	33,675	15,805
Transportation	4,507	3,601
General and administration	5,590	4,438
Interest	4,527	2,389
Stock-based compensation (note 5)	7,713	3,950
Accretion	631	363
Depletion and depreciation	60,929	40,920
Gain on financial derivative (note 8)	(190)	-
	117,382	71,466
Earnings before taxes	17,025	33,804
Income taxes (note 6)		
Capital and other taxes	957	958
Future income taxes	2,242	13,226
	3,199	14,184
NET EARNINGS	**13,826**	**19,620**
RETAINED EARNINGS (DEFICIT), BEGINNING OF YEAR	17,841	(1,779)
RETAINED EARNINGS, END OF YEAR	31,667	17,841
NET EARNINGS PER SHARE (note 5)		
Basic	$0.26	$0.45
Diluted	$0.25	$0.42
Weighted average Class A shares – basic	53,343,857	43,882,430
– diluted	55,907,653	46,569,053

See accompanying notes

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

($000s)	2006	2005
Cash provided by (used in):		
OPERATING ACTIVITIES		
Net earnings	13,826	19,620
Items not requiring cash:		
Future income taxes	2,242	13,226
Depletion and depreciation	60,929	40,920
Accretion	631	363
Stock-based compensation	7,713	3,950
Gain on financial derivative	(190)	-
Abandonment costs	(614)	-
Change in non-cash working capital	(39)	(6,125)
	84,498	71,954
FINANCING ACTIVITIES		
Issue of common shares	178,300	103,878
Share issue costs	(10,092)	(6,424)
Bank loan	47,694	26,895
	215,902	124,349
INVESTING ACTIVITIES		
Additions to equipment inventory	(1,429)	(272)
Additions to oil and gas properties	(283,348)	(106,929)
Acquisition of oil and gas properties (note 2)	(25,396)	(103,462)
Change in non-cash working capital	9,773	14,360
	(300,400)	(196,303)
CHANGE IN CASH	-	-
CASH, BEGINNING OF YEAR	-	-
CASH, END OF YEAR	-	-
SUPPLEMENTARY INFORMATION		
Cash interest paid	5,040	2,389
Cash taxes paid	1,208	958

See accompanying notes

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 5). 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. Equipment inventory is capitalized as part of property and equipment, but excluded from the depletable base until the equipment is put into use.

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.

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.

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.

Financial instruments

The Corporation periodically enters into commodity price derivative instruments to reduce the Corporation's exposure to adverse fluctuations in commodity prices. No contracts are entered into for trading or speculative purposes. Gains and losses relating to commodity swaps that meet hedge criteria are recognized in the statement of operations concurrently with the hedged transaction. Financial derivative instruments not designated as a hedge, not qualifying as a hedge, or no longer effective as a hedge are recorded on the balance sheet as an asset or liability with changes in fair value reflected in net earnings.

Fair Values

The carrying values of accounts receivable and accounts payable approximated their fair values at December 31, 2006 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.

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 "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. PROPERTY AND EQUIPMENT

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.

On May 18, 2005, the Corporation completed an acquisition of interests in certain oil and gas properties in the Dawson area of Alberta for cash of $91.4 million, net of closing adjustments.

As at December 31, 2006, $76.5 million (December 31, 2005 - $33.1 million) of undeveloped land, seismic and equipment inventory have been excluded from and $95.0 million (December 31, 2005 - $52.9 million) in future development costs have been added into the full cost pool for depletion purposes. For the year ended December 31, 2006, $660,500 (December 31, 2005 – $469,000) of exploration salaries have been capitalized.

As at December 31, 2006	Cost	Accumulated depletion	Net book value
	$	$	$
Petroleum and natural gas properties & equipment	688,354	(113,285)	575,069
Equipment inventory	2,536	-	2,536
Office furniture and equipment	671	(518)	153
	691,561	**(113,803)**	**577,758**

As at December 31, 2005	Cost	Accumulated depletion	Net book value
	$	$	$
Petroleum and natural gas properties & equipment	369,512	(52,768)	316,744
Equipment inventory	1,108	-	1,108
Office furniture and equipment	539	(106)	433
	371,159	**(52,874)**	**318,285**

The Corporation has performed the ceiling test using the benchmark reference prices at December 31, 2006 for the years 2007 to 2012 and adjusted for commodity differentials specific to the Corporation. Beyond year 2012, the price forecast escalates on average 2% per year. A foreign exchange rate of $0.86 US to $1.00 CDN was used. No impairment was required.

Benchmark Reference Price Forecasts:

	2007	2008	2009	2010	2011	2012
WTI oil USD/Bbl	65.00	65.52	64.27	61.73	59.07	59.11
Alberta spot gas $Cdn/Mcf	7.32	7.91	7.72	7.48	7.68	7.77

3. 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 $46.2 million, which will be incurred over the next 20 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	2006	2005
	$	$
Balance, beginning of year	11,186	3,998
Accretion expense	631	363
Liabilities incurred	6,149	821
Liabilities acquired	1,200	6,004
Revision of liabilities	2,880	-
Settlement of liabilities	(614)	-
Balance, end of year	**21,432**	**11,186**

4. AVAILABLE CREDIT FACILITY

The Corporation has a $170 million extendible revolving term credit facility in place with a bank syndicate. The facility bears interest at rates ranging from the bank's prime rate to prime plus 0.75% per annum 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 5.38% The borrowing base is subject to semi-annual review, the next review date being April 30, 2007. Collateral for the facilities consists of a demand debenture for $500 million secured by a first floating charge over all of the property and equipment of the Corporation.

5. 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, 2006 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, 2004 (a)	32,806,168	77,985
Issued for cash (b)	6,338,033	45,000
Issue of flow-through shares for cash (b)	2,400,000	20,000
Issue of subscription receipts for cash (c)	5,691,000	37,940
Issued for cash on exercise of stock options	505,125	939
Tax effect of flow-through shares	-	(8,750)
Share issue costs, net of tax of $2,243	-	(4,181)
Transfer from contributed surplus	-	323
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	**57,712,077**	**334,662**
Class B shares		
Balance at December 31, 2006 and December 31, 2005	922,500	5,207
Total share capital at December 31, 2006	**58,634,577**	**339,869**

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 February 10, 2005, the Corporation issued 6,338,033 Class A shares at $7.10 per share by way of private placement for gross proceeds of $45.0 million.

On May 12, 2005, the Corporation issued 2,400,000 flow-through Class A shares at $8.33 per share by way of private placement for gross proceeds of $20.0 million.

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.

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.

c) On May 12, 2005 the Corporation issued 5,691,000 subscription receipts at $6.67 each for gross proceeds of $37.9 million. Each subscription receipt entitled the holder to acquire one Class A Share of Galleon, without the payment of any additional consideration, upon the closing of the acquisition of properties at Dawson, Alberta.

Share options

The Corporation has a share option plan which was approved on May 19, 2005 and amended on August 25, 2005. 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	2006 $	2005 $
Contributed surplus, beginning of period	4,756	1,129
Stock based compensation expense	7,713	3,950
Transfer to share capital	(850)	(323)
Contributed surplus, end of period	**11,619**	**4,756**

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 2.00-3.28%; dividend yield of 0%; volatility factors of the market price of the Corporation's common shares of 40-46%; and, an average expected life of the options of 3 years.

	Number of Shares[1]	Weighted Average Exercise Price [1] $
Outstanding, December 31, 2004	2,689,001	2.49
Granted	2,557,500	8.25
Cancelled	(102,500)	(7.37)
Exercised	(505,125)	(1.86)
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**

[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, 2006:

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	348,500	1.75	0.23	348,500	0.23
2.84-8.70	2,765,325	2.85	5.92	2,150,825	5.62
9.67-14.33	759,000	3.83	12.88	426,000	6.48
16.07-22.83	1,437,500	4.42	19.85	479,165	19.85
	5,310,325	**3.34**	**10.28**	**3,404,490**	**7.18**

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, 2006, 997,500 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 56,384,049 (December 31, 2005 – 47,480,013). The prior year amounts have been restated to reflect the three-for-two Class A share split in June 2006.

6. INCOME TAXES

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

	2006 $	2005 $
Property and equipment	38,740	30,286
ACRI benefit	(870)	(832)
Share issue costs	(4,031)	(2,731)
Asset retirement obligation	(286)	(328)
Non-capital losses	(1,321)	-
Financial derivative	55	-
Future income tax liability	**32,287**	**26,395**

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 35.07% (December 31, 2005 – 38.02%).

Years ended December 31	2006 $	2005 $
Earnings before income tax	17,025	33,804
Corporate tax rate	35.07%	38.02%
Expected tax	5,971	12,855
Increase (decrease) in taxes resulting from:		
Non-deductible crown payments	2,584	6,804
Resource allowance	(2,524)	(5,886)
Attributed crown royalty income	(154)	(515)
Stock-based compensation	2,705	1,501
Statutory tax rate changes	(5,972)	(1,404)
Capital and other taxes	957	958
Other	(368)	(129)
	3,199	**14,184**

As at December 31, 2006 Galleon has approximately $440.5 million (December 31, 2005 – $227.6 million) of tax deductions for Canadian income tax purposes. This includes a tax loss of approximately $4.0 million which can be used to offset taxable income until 2016.

7. 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 is expected to commence January, 2007. Future minimum payments under this contract are as follows:

Year	Amount $
2007	4,554
2008	4,554

Equipment:
The Corporation has made installment payments of $4.4 million related to equipment which will be delivered in the first quarter of 2007. The installment payments have been recorded as additions to property and equipment. Additional future commitments for this equipment are $0.3 million.

Minimum Lease Payments:
At December 31, 2006 the Corporation has committed to future minimum payments under operating leases that cover office space as follows:

Year	Amount $
2007	472
2008	280

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 offering in 2006, Galleon is obligated to spend $40.0 million on qualifying exploration expenses prior to December 2007. As at December 31, 2006, it is estimated that $17.0 million remains to be incurred. Galleon will recognize the associated future income tax liability upon renunciation of the exploration expenses in the first quarter of 2007.

8. RISK MANAGEMENT

The Corporation has the following fixed price physical contracts in place:

Natural Gas:		
November 1, 2006 – March 31, 2007	5,000 GJ/day	CDN $7.51 GJ
February 2007	5,000 GJ/day	CDN $7.00 GJ
February 2007	5,000 GJ/day	CDN $7.25 GJ
February 2007	5,000 GJ/day	CDN $7.50 GJ
March 2007	5,000 GJ/day	CDN $7.02 GJ
March 2007	5,000 GJ/day	CDN $7.26 GJ
March 2007	5,000 GJ/day	CDN $7.50 GJ
April 1, 2007 – October 31, 2007	5,000 GJ/day	CDN $6.64 GJ
April 1, 2007 – October 31, 2007	5,000 GJ/day	CDN $6.50 - $8.12 GJ
April 1, 2007 – October 31, 2007	5,000 GJ/day	CDN $7.50 GJ

The Corporation has the following costless collar financial derivative in place:

Crude Oil:		
January 1, 2007 – December 31, 2007	1,000 bbl/d	WTI USD $61.75-$70.00/bbl

Galleon entered into the above contract as a means of managing commodity price volatility. The fair value of the financial derivative at December 31, 2006 is recorded on the balance sheet as a financial derivative asset, based on quoted market prices. Changes in fair value are recorded on the balance sheet with the associated gain or loss recorded in earnings.

9. SUBSEQUENT EVENTS

Subsequent to December 31, 2006, the Corporation increased its existing extendible revolving credit facilities to $180 million and added an additional $28.5 million non-revolving facility with a Canadian chartered bank in order to fund the acquisition of an interest in a partnership. On February 1, 2007 the Corporation purchased the interest in the partnership and the minority partnership interest holder for total cash consideration $28.6 million. The partnership holds oil and gas assets within Galleon's core area of Dawson, Alberta.

10. COMPARATIVE FIGURES

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

GALLEON
ENERGY INC.

Management Discussion and Analysis

DECEMBER 31, 2006

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, 2006 with comparisons to the year ended December 31, 2005. 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 financial statements for the year ended December 31, 2006.

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

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

This MD&A is based on information available as of, and is dated, March 13, 2007.

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, expected growth areas, operating costs, drilling plans and the timing thereof, commodity prices, effects on taxable income as a result of tax changes, plans to reduce operating costs for heavy oil, effect of new facilities, expected interest costs and accretion expense, expected commodity mix, 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.

2006 Performance

The momentum continued in 2006. During the year, the successful advancement and expansion of the three key projects, Puskwa, Dawson Montney gas and Eaglesham, led to tremendous growth in production and substantial value creation in reserves.

- 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 $894 million, an 78% increase over December 31, 2005;
- Gross proved plus probable reserves grew to 50.4 million BOE, an increase of 54% over December 31, 2005 – over 80% of this increase was due to growth in light oil reserves;
- Gross proved reserves grew to 28.3 million BOE, an increase of 37%;
- Gross proved plus probable reserve life index increased to 12.7 years based on average Q4 2006 production;
- Production on a proved plus probable basis was replaced 5.2 times;
- Gross proved plus probable reserves improved to 36% light oil, 38% natural gas, 25% heavy oil and 1% natural gas liquids;
- Access to over 1 million gross acres of land, approximately 70% net owned, has been assembled;
- An inventory of over 500 drilling locations has been identified.

The light sweet oil discovery at Puskwa, Alberta was announced in March 2006. This first well tested over 2,500 bbl/d from the Beaverhill lake formation. An additional 10 wells were drilled in 2006 resulting in tested capacity exceeding 11,150 bbl/d by year end. Although significant proved and probable reserves were recorded at Puskwa in 2006, the large oil pool has been only partially developed.

In 2006, $22.2 million was expended on a natural gas plant and a crude oil battery at Puskwa. The facilities have excess capacity for production growth and have placed Galleon in a solid position to control costs and infrastructure. Galleon plans to drill up to 30 wells at Puskwa in the next 2 years.

The Montney natural gas project in Dawson, Alberta delivered large production and reserves additions in 2006. Production in fourth quarter 2006 averaged 11.2 MMcf/d compared to 2.6 MMcf/d in fourth quarter 2005. With approximately 300 locations identified on over 600 sections of land, this project has the potential to add incremental production and reserves for many years. Due to the low cost of drilling and operations, the economics of this project are very strong at current commodity prices.

At Eaglesham, Alberta, 9 wells were drilled and cased for liquids rich natural gas and resulted in average production during fourth quarter 2006 of 845 BOE/d. A gas plant commenced operations in 2006 and has additional capacity for future growth.

2006 Financial Highlights

- Funds from operations were $85.2 million ($1.60 per basic share), an increase of 9% from 2005;
- Earnings of $13.8 million ($0.26 per basic share) were generated from revenues of $157.9 million;
- Daily production averaged 9,370 BOE; natural gas – 32.6 MMcf and crude oil and NGLs – 3,939 bbl, an increase of 43% from 2005;
- Drilled 118 gross wells resulting in 72 (59.9 net) natural gas wells, 28 (22.1 net) light oil wells and 6 (6.0 net) heavy oil wells; a success rate of 90% ;
- Spent $283.3 million on exploration and development activities including $92.1 million on facilities, plus property acquisitions of $25.4 million;
- Completed three share equity issuances for gross proceeds of $175.2 million and the issuance of 8,995,700 Class A shares;
- Completed a three for two Class A share split in June 2006;
- Increased the extendible revolving bank credit facility to $170 million.

Annual Information

($000s)	2006	2005	2004
Revenues	157,931	135,050	21,652
Funds from Operations[1]	85,151	78,079	10,227
Per share, basic[1]	1.60	1.78	0.38
Per share, diluted[1]	1.52	1.68	0.35
Net Earnings (Loss)	13,826	19,620	(168)
Per share, basic	0.26	0.45	(0.01)
Per share, diluted	0.25	0.42	(0.01)
Total Assets	614,565	352,619	160,892
Net debt	151,213	93,783	58,656

[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.

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 increases to funds from operations, net income, and total assets.

In 2004, the Corporation purchased interests in oil and gas properties, gas plants, and gathering systems in the Dawson area for cash of $47 million. On July 28, 2004 Galleon acquired all issued and outstanding shares of Inisfail Energy Ltd. for a purchase price of $16.1 million. On January 15, 2004 the Corporation acquired all of the issued and outstanding shares of Venture Energy Inc. for a purchase price of $17.8 million.

Results of Operations

Comparative financial results for the year are as follows:

Year ended December 31	2006		2005	
	3,420,198 BOE		2,386,759 BOE	
($000s)		$/BOE		$/BOE
Revenues	157,931	46.18	135,050	56.58
Royalties	(32,900)	(9.62)	(33,385)	(13.99)
ARTC and GCA	9,371	2.74	3,580	1.50
Transportation costs	(4,507)	(1.32)	(3,601)	(1.51)
Operating costs	(33,675)	(9.85)	(15,805)	(6.62)
Net	**96,220**	**28.13**	**85,839**	**35.96**
Other revenue	5	-	25	0.01
G&A	(5,590)	(1.63)	(4,438)	(1.86)
Interest costs	(4,527)	(1.32)	(2,389)	(1.00)
Capital and other taxes	(957)	(0.28)	(958)	(0.40)
Funds from operations[1]	**85,151**	**24.90**	**78,079**	**32.71**

[1] See "Non-GAAP measurements"

Petroleum and Natural Gas Revenues

Year ended December 31	2006		2005	
($000s)		%		%
Light oil	50,139	32	42,097	31
Heavy oil	25,131	16	9,853	7
NGLs	2,919	2	1,159	1
Natural gas	79,125	50	81,252	60
Royalty income	617	-	689	1
Total	**157,931**	100	**135,050**	100

Revenues for the year ended December 31, 2006 increased 17% to $157.9 million from $135.1 million in the prior year due to a 43% increase in average production volumes. The overall price received decreased to $46.18/BOE from $56.58/BOE a year ago as a result of lower natural gas prices. Average natural gas prices decreased 28% year over year.

Production

Year ended December 31	2006		2005	
	BOE/d	%	BOE/d	%
Light oil (Bbls/d)	1,963	21	1,643	25
Heavy oil (Bbls/d)	1,845	20	788	12
NGLs (Bbls/d)	131	1	57	1
Natural gas (Mcf/d)	32,584	58	24,302	62
BOE/d (6:1)	**9,370**	100	**6,539**	100

Average production volumes for 2006 of 9,370 BOE/d increased 43% compared to 6,539 BOE/d in 2005. By product, heavy oil volumes increased 134%, natural gas volumes increased 34%, and light oil volumes increased 19%. Heavy oil production increased as a result of optimization techniques and minor workovers at Edam. Natural gas production increased as a result of Montney gas drilling success in the Dawson area and new natural gas production from Galleon's emerging Eaglesham area. Light oil production increased as a result of drilling success at Puskwa. During the year Galleon drilled 118 wells and cased 106 for production, for a success rate of 90%; 48% of these wells were exploratory. Wells cased for production include 28 (22.1 net) light oil wells, 72 (59.9 net) natural gas wells and 6 (6.0 net) heavy oil wells.

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, Galleon entered into fixed price natural gas contracts for the period November 1, 2006 to October 31, 2007, details of which are disclosed in note 8 to the financial statements. For crude oil, Galleon implemented a costless collar on 1,000 bbls a day, fixing a floor price of WTI USD $61.75/bbl and a ceiling of WTI USD $70.00/bbl for the period January 1, 2007 to December 31, 2007. See "Financial Instruments".

Prices (net of transportation)

Year ended December 31	2006	2005
Light oil ($/Bbl)	68.81	68.32
Heavy oil ($/Bbl)	36.75	34.24
Natural gas ($/Mcf)	6.44	8.95
NGLs ($/Bbl)	60.84	55.41

The average natural gas price received for 2006 of $6.44/Mcf decreased 28% compared to $8.95/Mcf in the prior year. For the same period, the average AECO natural gas spot price decreased 25%. For 2007, management has budgeted an average AECO price of $6.50/Mcf.

The average light oil price received for 2006 was $68.81/bbl compared to $68.32/bbl in the prior year. Average heavy oil prices of $36.75/bbl increased 7% compared to the prior year as a result of a decrease in differentials. For 2007, management has budgeted an average WTI price of USD $60.00.

Performance by Property

Year ended December 31	2006			2005			
	Production		Operating netbacks/ BOE [1]	Production		Operating netbacks/ BOE[1]	2006 Funds from operations[2]
	BOE/d	%	$	BOE/d	%	$	%
Puskwa	657	7	55.55	-	-	-	15
Dawson Montney gas	1,120	12	23.18	200	3	43.29	11
Eaglesham	280	3	35.42	-	-	-	4
Dawson	4,010	43	28.62	4,123	63	39.06	48
Calais	1,002	11	26.62	815	13	33.28	12
Edam and other heavy oil	1,846	20	7.57	788	12	10.89	6
Other	455	4	22.32	613	9	32.62	4
	9,370	100	**25.39**	**6,539**	100	**34.46**	100

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

Two new core areas were established during the year, Puskwa and Eaglesham. A significant light oil pool discovery was made at Puskwa in March, 2006. Subsequent drilling proved substantial oil reserves. Puskwa contributed 15% of annual funds from operations from 7% of total production. Producing wells generated strong operating netbacks of $55.55/BOE driven by low operating costs of $2.91/BOE and high light oil prices, net of transportation, of $69.15/bbl. The high light oil price received is indicative of the quality of the 38 degree API sweet oil. As the majority of the wells at Puskwa commenced production in the second half of the year, and due to the EUB imposed production restrictions, annual average production from Puskwa was 657 BOE/day, while current tested production capacity is in excess of 11,150 BOE/d, net to Galleon. Galleon has prepared an application for removal of the EUB imposed production restrictions. The expected timing of the removal is not known at this time. Additional production will be brought on stream upon approval from the EUB. Galleon plans to drill up to 15 new wells in the Puskwa area in 2007.

Liquids rich natural gas and light oil production at Eaglesham commenced in August, 2006 and reached 845 BOE/day by the fourth quarter of 2006. Ownership and control of the facilities in the area has enabled Galleon to control operating costs. 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. Galleon plans to drill up to 10 wells in this area in 2007.

Production of Montney gas at Dawson increased 460% compared to 2005 due to a successful drilling program. Operating netbacks decreased by $20.11/BOE, or 46%, due primarily to lower natural gas prices. The decline in price impacted the netback by $22.68/BOE, higher operating costs reduced the netback by $1.26/BOE, and lower royalties offset these reductions by $3.83/BOE. Galleon has identified over 300 drilling locations in the Dawson area and plans to drill up to 60 wells in 2007.

The Dawson area was the largest contributor to Galleon's funds from operations, contributing 48% of total operating cash flow from 43% of total production. Production from the area decreased by 3% compared to the previous year as a result of reduced capital spending.

The heavy oil wells contributed 6% of annual funds from operations from 20% of total production. Operating netbacks of $7.57/BOE decreased 30% compared to the prior year as a result of higher operating costs.

Royalties

Year ended December 31	2006	2005
($000s)		
Crown	29,985	31,180
Freehold	1,134	720
GORR and other	1,781	1,485
Subtotal	**32,900**	**33,385**
ARTC and GCA	(9,371)	(3,580)
Net royalties	**23,529**	**29,805**
% of revenue	**20.8**	**24.7**
% of revenue net of ARTC and GCA	**14.9**	**22.1**

Gross royalties were 20.8% of revenues for 2006 compared to 24.7 % in 2005. 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. For 2005 gross royalties were 23.9% for light oil, 26.9% for natural gas, 17.8% for heavy oil, and 25.4% for liquids. Average royalties in 2006 decreased due to royalty holidays on several deep light oil wells drilled during the year. Net royalties of 14.9% decreased 33% compared to the prior year as a result of additional Gas Cost Allowance (GCA) credits attributed to Galleon's new natural gas facilities.

During 2005 and 2006 Galleon received $500,000 of Alberta Royalty Tax credits (ARTC). For 2007 the ARTC program has been discontinued, however all of Galleon's Crown royalty payments will become deductible for tax purposes. Previously only a portion of Crown payments were deductible for income tax purposes. Galleon estimates the reduction in taxable income as a result of the tax changes will amount to more than the $500,000 foregone tax credit.

Operating Costs

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	-	(1.58)
Dawson	43	34	7.88
Calais	11	7	6.02
Edam and other heavy oil	20	44	21.93
Other	4	6	12.97
	100	100	**9.85**

Year ended December 31	2005		
	Production %	Operating costs %	Operating costs $/BOE
Puskwa	-	-	-
Dawson Montney gas	3	2	4.78
Eaglesham	-	-	-
Dawson	63	44	4.63
Calais	13	9	5.03
Edam and other heavy oil	12	32	17.29
Other	9	13	9.02
	100	100	**6.62**

Operating costs were $33.7 million or $9.85/BOE for the year ended December 31, 2006 compared to $15.8 million or $6.62/BOE for the prior year. Galleon's operating costs per barrel of oil equivalent excluding the heavy oil was $6.88/BOE for the year. Costs for the heavy oil assets increased from $17.29/BOE in 2005 to $21.93/BOE in 2006. In the second half of 2006 the non-operated heavy oil facility that processed Galleon's production was destroyed by fire. Galleon was required to truck its heavy oil to a facility that was farther from its producing wells. This resulted in an increase in heavy oil trucking costs of $2.02/BOE in 2006 compared to 2005. Other cost increases for heavy oil were due to a greater number of well services and minor workovers necessary to maintain current production volumes. In the first quarter of 2007 Galleon plans to implement cost saving strategies to reduce operating costs for heavy oil.

Operating costs per barrel of oil equivalent for Dawson Montney gas increased due to fixed costs related to the initial start-up of the new natural gas plant. Additional costs were incurred for utilities, compressor maintenance, and contract operators. The 30 MMcf/day gas plant is now fully operational and it is expected greater economies of scale will be achieved in 2007.

Costs for the oil properties at Dawson increased due to declining volumes and increased well services and minor workovers. Operating costs were low at Puskwa and Eaglesham where Galleon controls the facilities and drilled several highly productive wells during 2006.

General and Administration Expenses

Year ended December 31	2006		2005	
($000s)		$/BOE		$/BOE
Gross	9,926	2.90	6,642	2.79
Capitalized overhead	(661)	(0.20)	(469)	(0.20)-
Overhead recoveries	(3,675)	(1.07)	(1,735)	(0.73)
	5,590	**1.63**	**4,438**	**1.86**

Net general and administrative (G&A) expenses of $1.63/BOE for 2006 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. 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 49% with the growth of the Corporation, gross G&A expenses per barrel of oil equivalent have only increased by 4%. This is indicative of the efficiencies gained through production growth.

For the year ended December 31, 2006 G&A expenses by category were: salary and employee – 51%, office – 15%, corporate – 10%, audit, engineering and legal – 9%, consulting – 10%, and computer – 5%.

Interest

Interest expense of $4.5 million for the year ended December 31, 2006 was higher compared to $2.4 million in the prior year due to increased average debt levels. The effective interest rate was 5.38%. As at December 31, 2006 Galleon's bank debt to equity ratio of 0.32 remains low and has decreased from 0.38 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 2007 interest costs are expected to increase due to higher average debt levels.

Stock Based Compensation

Stock based compensation was a non-cash expense of $7.7 million for the year compared to $4.0 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 1,647,500 stock options were granted at an average exercise price of $19.13 and had fair values of between $4.38 and $7.41 per option.

At December 31, 2006, 5,310,325 stock options were outstanding at an average exercise price of $10.28.

Depletion, Depreciation and Accretion

Depletion and depreciation ("D&D") charges were $60.9 million or $17.81/BOE for the year ended December 31, 2006 compared to $40.9 million or $17.14/BOE in the prior year. The D&D rate increase was due to $92.1 million of investments in 2006 for production facilities for which the benefits will be realized over a number of years, and the increase in future development costs associated with the development of the Montney gas and Puskwa oil projects.

Reserve additions for 2006 were estimated by an independent third party qualified reserves evaluator. Capital expenditures of $76.5 million ($33.1 million – December 31, 2005) related to undeveloped land, seismic, and equipment inventory have been excluded from the depletion and depreciation calculation and $95.0 million ($52.9 million – December 31, 2005) of future development costs have been added.

Accretion expense on the Corporation's asset retirement obligation was $631,000 for the year compared to $363,000 in the prior year. The increase related to a greater asset retirement obligation which is driven by the number of wells and facilities in which Galleon has an interest. At December 31, 2006 Galleon re-evaluated its asset retirement obligation and revised its estimates upwards to reflect the increase in industry costs experienced during the year. As well, the inflation rate was adjusted upwards from 1.5% to

2.0% to reflect Galleon's expectations of cost increases over the next 20 years. The credit adjusted risk free rate was increased to 8% from 5% in consideration of the current interest rate environment and Galleon's expectation of interest rates over the 20 year life of the obligation. As a result of these changes, it is expected that the accretion expense will increase during 2007.

Capital and Future Taxes

The current tax provision of $957,000 for the year was comprised of Saskatchewan capital and resource taxes. In 2005, the current tax provision of $958,000 was comprised of both federal large corporation tax and the Saskatchewan capital and resource taxes. The federal large corporation tax was eliminated for fiscal 2006. Galleon's provision for Saskatchewan taxes has increased due to higher revenue from Saskatchewan in 2006 compared to 2005.

The provision for future income taxes was $2.2 million for the year ended December 31, 2006 compared to $13.2 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 $440.5 million as at December 31, 2006.

Capital Expenditures

($000s)	
Property & equipment balance at December 31, 2005	318,285
Additions to equipment inventory	1,429
Additions to property and equipment	283,348
Acquisition of property and equipment	25,396
Asset retirement obligation	10,229
Depletion and depreciation	(60,929)
Property & equipment balance at December 31, 2006	**577,758**

Year ended December 31	**2006**		**2005**	
($000s)		%		%
Land	31,385	11	5,735	5
Geological and geophysical	22,947	8	11,882	11
Drilling and completion	136,740	48	57,748	55
Plant and facilities	92,144	33	31,189	29
Other assets	132	-	375	-
Exploration and Development Expenditures	**283,348**	100	**106,929**	100

Capital expenditures during 2006 included $25.4 million for the acquisition of oil and gas properties in the Dawson area, and $283.3 million on exploration and development expenditures. Galleon completed its most active drilling program in 2006, drilling 118 wells. By key area, 11 wells were drilled at Puskwa, 9 wells were drilled at Eaglesham, and 50 wells were drilled for Montney gas.

At Puswka, highly productive light oil wells were drilled spanning a distance of 5 miles. Drilling to date has established significant oil reserves. Further drilling in 2007 will focus on developing the pool and delineating the north-eastern boundary. At Eaglesham, several multi-zone oil and gas wells were drilled targeting the Dunvegan to Wabamun formations. Galleon's development drilling included the continued expansion of its sizeable Dawson Montney gas play.

Facilities were added in all three of the above key areas in order to accommodate production growth. Facilities investments included $21.1 million for the construction of a 30 MMcf/d natural gas plant at Dawson, $22.2 million for a 10 MMcf/d natural gas plant and 10,000 bbl/d oil battery at Puskwa, and $13.9 million for a 15 MMcf/ day natural gas plant at Eaglesham. It is expected these investments will provide Galleon with sufficient capacity to meet expected production growth in 2007.

Land and seismic expenditures in 2006 were concentrated in the above three key areas. Management has established a capital budget of between $170 to $220 million for 2007 and plans to finance the program with funds from operating activities and with expanded credit facilities.

Liquidity and Capital Resources

Year ended December 31	2006	2005
($000s)		
Bank debt	122,996	75,301
Working capital deficiency	28,217	18,482
Total net debt	**151,213**	**93,783**

Funding of Capital Program

Year ended December 31	2006	2005
($000s)		
Issuance of shares, net of costs	168,208	97,454
Funds from operations	85,151	78,079
Change in bank debt	47,694	26,895
Change in working capital and other	7,691	7,963
	308,744	**210,391**

During the year, net proceeds of $168.2 million from equity offerings, funds from operations of $85.2 million, and an additional $55.3 million in bank debt and working capital were used to fund $308.7 million of acquisition and exploration and development expenditures.

At December 31, 2006, the Corporation has $170 million extendible revolving term credit facilities with a syndicate of Canadian chartered banks. The facilities are secured by a first floating charge demand debenture in the amount of $500 million over property and equipment of the Corporation. At December 31, 2006, $123.0 million was drawn on the credit facilities.

Subsequent to December 31, 2006 the banks approved an increase in the extendible revolving term credit facility to $180 million and a $28.5 million by way of a non-revolving facility to fund the acquisition of an interest in a partnership holding oil and gas assets in the Dawson area. For further information see note 9 to the financial statements.

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 2007 prices and production volumes.

Change to annual funds from operations	Change	$000s	$/share[2]
Price per barrel of oil (US$ WTI)[1]	$1.00	1,672	0.03
Price per Mcf of natural gas (C$ AECO)[1]	$0.50	6,907	0.12
Oil production volumes	100 bbl/d	1,373	0.02
Gas production volumes	1 MMcf/d	1,296	0.02
Exchange rate (US/Canadian)	$0.01	1,103	0.02
Interest rate on debt ($120 Million)	1%	1,200	0.02

[1] After adjustment for estimated royalties.

[2] Based on diluted shares outstanding at December 31, 2006.

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 is expected to commence in January, 2007. Future minimum payments under this contract are as follows:

Year	Amount ($000s)
2007	4,554
2008	4,554

Equipment:
The Corporation has made installment payments of $4.4 million related to equipment which will be delivered in the first quarter of 2007. The installment payments have been recorded as additions to property and equipment. Additional future commitments for this equipment are $0.3 million.

Minimum Lease Payments:
At December 31, 2006 the Corporation has committed to future minimum payments under operating leases that cover office space as follows:

Year	Amount ($000s)
2007	472
2008	280

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 offering in 2006, Galleon is obligated to spend $40.0 million on qualifying exploration expenses prior to December 2007. As at December 31, 2006, it is estimated that $17.0 million remains to be incurred. Galleon will recognize the associated future income tax liability upon renunciation of the exploration expenses in the first quarter of 2007.

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 fixed price physical contracts in place for natural gas and a costless collar derivative contract for crude oil prices. 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 Company. 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 Company and its operations and financial condition.

Financial Instruments

As a means of managing the risk of commodity price volatility, in December 2006, Galleon entered into a financial contract with a Canadian chartered bank, setting a floor price of USD WTI $61.75/bbl and a ceiling of USD WTI $70.00/bbl on 1,000 bbl per day of crude oil for the period January 1, 2007 to December 31, 2007. The contract will protect base line revenues if the WTI crude oil benchmark falls below $61.75/bbl. The contract is a costless collar, therefore no premium was paid by Galleon upon entering into the contract. The contract will be settled monthly based on the average USD WTI benchmark price. Galleon will receive payments on the contract if the benchmark USD WTI price falls below $61.75/bbl and will be required to make payments if the price rises above $70.00/bbl. Galleon has recognized this financial instrument on its balance sheet at fair value, and is accounting for the instrument using mark to market accounting. As at December 31, 2006 Galleon has an unrealized gain of $190,000 related to this derivative instrument.

Summary of Quarterly Results

Quarterly Highlights (unaudited)	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

Quarterly Highlights	2005			
	Q4	Q3	Q2	Q1
Financial ($000s)				
Revenues	51,989	44,506	24,743	13,812
Operating costs	(6,311)	(5,179)	(2,727)	(1,588)
G&A	(1,489)	(1,171)	(1,030)	(748)
Interest	(742)	(668)	(558)	(420)
Funds from operations[2]	**29,662**	**27,325**	**13,782**	**7,311**
Per share, basic[1, 2]	0.62	0.57	0.32	0.20
Per share, diluted[1, 2]	0.59	0.54	0.30	0.20
Earnings	**9,324**	**9,112**	**689**	**495**
Per share, basic[1]	0.20	0.19	0.02	0.01
Per share, diluted[1]	0.18	0.18	0.02	0.01
Total assets	**352,619**	**312,523**	**290,883**	**180,363**
Weighted average outstanding Class A shares-basic[1]	47,698,056	47,640,620	43,467,068	36,560,286
Weighted average outstanding Class A shares-diluted[1]	50,599,782	50,268,840	45,474,116	38,072,111

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

[2]See "Non-GAAP Measurements".

During 2006, the quarterly increases in total assets 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, as prices received per barrel of oil equivalent did not fluctuate significantly during the year.

During 2005, total assets increased in the second quarter as a result of the significant acquisition of oil and gas assets in the Dawson, Alberta area on May 18, 2005. Revenues and funds from operations increased during the third quarter, reflecting the first full quarter of operating results relating to the asset acquisition. In the fourth quarter, revenues and funds from operations increased as a result of an increase in average realized natural gas prices.

Fourth Quarter Results

Three months ended December 31	2006		2005	
	999,982 BOE		816,420 BOE	
($000s)	$	$/BOE	$	$/BOE
Revenues	45,264	45.26	51,989	63.68
Royalties	(9,421)	(9.42)	(13,948)	(17.09)
ARTC and GCA	3,404	3.40	1,694	2.08
Transportation costs	(1,372)	(1.37)	(1,206)	(1.48)
Operating costs	(9,651)	(9.65)	(6,311)	(7.73)
Net	**28,224**	**28.22**	**32,218**	**39.46**
Other revenue	2	-	1	-
G&A	(2,670)	(2.67)	(1,489)	(1.82)
Interest costs	(1,487)	(1.49)	(742)	(0.91)
Capital and other taxes	(212)	(0.21)	(326)	(0.40)
Funds from operations	**23,857**	**23.85**	**29,662**	**36.33**

For the three months ended December 31, 2006 production increased 22% to 10,869 BOE/d compared to 8,874 BOE/d in the same period of the prior year. Revenues were less as a result of lower commodity prices partially offset by greater volumes. Average natural gas prices of $6.84/Mcf were 39% lower than $11.16/Mcf in Q4 2005. Average light oil prices of $61.12/bbl were 9% lower than $67.44/bbl realized in the prior year. Average heavy oil prices of $31.16/bbl were 6% higher than the prior year.

Net royalty rates of 13.3% of revenues decreased compared to 23.5% in Q4 2005. The decrease was a result of additional GCA credits from the Crown due to Galleon's investments in natural gas plants during 2006.

Operating costs increased as the heavy oil assets comprised a larger proportion of total production compared to the same period a year ago. Major operating costs at Edam include well services and minor workovers, trucking charges, and propane and fuel. Operating costs in all other areas averaged $6.12/BOE. The operating netback of $28.22/BOE is 28% lower than $39.46/BOE in the same period in 2005.

G&A expenses of $2.67/BOE increased 47% compared to $1.82/BOE in Q4 2005 due to higher costs for the independent reserves evaluation report and greater expenses for salaries, consulting services, and bonuses due to additional employees and consultants. Interest costs of $1.49/BOE were 64% higher than $0.91/BOE in the prior year as a result of higher average debt levels. Higher debt levels were due to Galleon's capital expenditure program in 2006. Capital and other taxes of $0.21/BOE were lower than $0.40/BOE in the prior year as a result of the elimination of the federal large corporation tax. Funds from operations of $23.9 million ($0.42 per share) decreased 20% from $29.7 million ($0.62 per share) in the fourth quarter of the prior year. Funds from operations of $23.85/BOE were 34% lower than $36.33/BOE in the same period of 2005.

Capital expenditures of $79.4 million were incurred during the quarter, with 49% spent on drilling and completions activity, 24% on plant and facilities, 20% on land, 6% on seismic, and 1% on other assets. Galleon drilled 29 wells and cased 26 (20.2 net) for a 90% success rate. Successful wells included 8 (5.8 net) light oil wells and 18 (14.4 net) natural gas wells. Facility expenditures were for the completion of the 30MMcf/d Montney gas plant expansion. Land was acquired in the north-eastern area of Puskwa. Galleon plans to drill an exploration well in Q1 2007 in this area to test the northern boundary.

The fourth quarter capital program was funded by $23.9 million of funds from operations, $37.9 million of net proceeds from an equity offering and $17.6 million of working capital and bank debt.

Performance by Property

Three months ended December 31	2006			2005			
			Operating netbacks/ BOE [1]			Operating netbacks/ BOE[1]	Q4 2006 funds from operations
	BOE/d	%	$	BOE/d	%	$	%
Puskwa	1,286	12	45.26	-	-	-	22
Dawson Montney gas	1,869	17	25.81	431	5	44.91	18
Eaglesham	845	8	39.42	-	-	-	12
Dawson	3,669	34	27.52	5,318	60	42.16	37
Calais	714	7	23.61	1,398	16	39.62	6
Edam and other heavy oil	2,100	19	1.07	1,139	13	5.36	1
Other	386	3	25.80	588	6	45.36	4
	10,869	100	**24.82**	**8,874**	100	**37.38**	100

[1] Operating netbacks/BOE exclude ARTC and GCA and are calculated by subtracting royalties and operating costs from revenues.

Production grew at Puskwa and Eaglesham as the result of several high impact wells drilled during the year. The high deliverability wells are indicative of the quality of the reservoirs in the area. Galleon realized strong operating netbacks at Puskwa of $45.26/BOE due to average light oil prices of $62.81/BOE and low operating costs of $2.89/BOE. Puskwa generated 22% of Q4 2006 funds from operations from 12% of production. At Eaglesham, operating netbacks were $39.42/BOE, with average prices of $45.15/BOE and net operating costs of $(3.52)/BOE. The operating costs are net of $8.70/BOE of processing revenues from the gas plant. Eaglesham generated 12% of Q4 2006 funds from operations from 8% of total production.

Production from Montney gas grew 334% in Q4 2006 compared to Q4 2005 due to successful drilling. Galleon cased 13 Montney gas wells during the quarter. Operating netbacks of $4.31/Mcf were lower as a result of weaker natural gas prices. Average natural gas prices received were $6.83/Mcf. Operating costs were $0.72/Mcf.

The Dawson area contributed 37% of total funds from operations from 34% of production. Operating netbacks are lower than the prior year due to a significant decrease in natural gas prices. The production decline of 31% was associated with the decline in production from light oil wells at Dreau.

Heavy oil production grew 84% as a result of exploitation techniques. Operating netbacks are less than the prior year due to increased operating costs associated with maintaining stable production volumes. In the first quarter of 2007 Galleon plans to implement cost saving strategies to reduce operating costs for heavy oil. Excluding the heavy oil assets, Galleon's operating netback prior to ARTC and GCA was $30.51/BOE in 2006 compared to $42.10/BOE in 2005. With exit production for 2007 planned to be between 17,000-21,000 BOE/d, it is expected that the heavy oil assets will only account for 10%-12% of total production by the end of 2007.

Critical Accounting Estimates

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

Oil and Gas Accounting

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

Proved Reserves

Full cost accounting relies on the estimated proved reserves believed to be recoverable from the oil and gas properties. Determination of reserves is a complex process involving judgments, estimates and decisions based on available geological, engineering/production and other relevant economic data. These estimates are subject to change as economic conditions change and ongoing production and development activities provide new information. The Corporation's reserves are evaluated 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 Company recognizes goodwill on corporate acquisitions when the total purchase price exceeds the fair value of net identifiable assets and liabilities of the acquired entity. Goodwill is tested 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

Financial Instruments

In April 2005, the Canadian Institute of Chartered Accountants issued the following new Handbook Sections: Section 1530, Comprehensive Income; Section 3251, Equity; Section 3855, Financial Instruments – Recognition and Measurement; and Section 3865, Hedges. The effective date for adoption for all four sections is for fiscal years beginning on or after October 1, 2006. These new accounting standards for Canadian GAAP will converge more closely with US GAAP as all financial instruments will be recorded on the balance sheet at fair value and changes in fair value will be included in earnings, except for derivative financial instruments designated as hedges, for which changes in fair value will be included in comprehensive income. As the Corporation currently accounts for its derivative financial instruments at fair value, management does not believe these sections will have a significant impact on future financial statements.

Changes in Accounting Policies and Estimates, and Errors

In July 2006, the Canadian Institute of Chartered Accountants issued Handbook section 1300, Changes in Accounting Policies and Estimates, and Errors. This new section applies to interim and annual financial statements for fiscal years beginning on or after January 1, 2007. This new section permits changes to accounting policies only when it is required by a primary source of GAAP, or when the change results in a reliable and more relevant presentation in the financial statements. The section requires expanded disclosure about the effects of changes in accounting policy, estimates and errors on the financial statements, and disclosure of new primary sources of GAAP that have been issued but have not yet come into effect and have not yet been adopted by the entity. Management does not believe this section will have a significant impact on future financial statements.

Controls and Procedures over Financial Reporting

Galleon has established disclosure controls and procedures to provide reasonable assurance that material information relating to Galleon is made known to the Chief Executive Officer (CEO) and the Chief Financial Officer (CFO) by others within the Corporation, particularly during the period in which the annual filings have been 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 GAAP.

The Company'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 Energy as of December 31 for the respective year ends:

	2006	2005[1]
Class A shares outstanding		
Basic	57,712,077	47,740,314
Diluted[2]	63,022,402	52,379,190
Class B shares outstanding	922,500	922,500
Class A shares issuable on conversion of Class B shares[3]	510,232	564,911

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

[2] Includes outstanding options of 5,310,325 (December 31, 2005 – 4,638,876).

[3] Assumes a conversion at the December 31, 2006 closing price of $18.08 per Class A share (December 31, 2005 -$16.33). The actual conversion rate varies based on a formula related to the trading price of the Class A shares.

At December 31, 2006, the market value of Galleon's class A and class B shares was $1,051.3 million based on the December 31, 2006 closing price of $18.08 per class A share and $8.50 per class B share. As of March 13, 2007, the number of class A shares, class B shares, and options outstanding is 57,867,077, 922,500, and 5,405,325 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

Galleon expects that production growth will vary from 5-15% per quarter during 2007. Based on field receipt estimates and planned production additions, production growth in Q1 and Q2 2007 is expected to be in the mid-range of this guidance. Based on weekly field estimates, recent production has averaged between 12,500 and 13,000 BOE/d. Estimated 2007 exit production is targeted between 17,000 and 21,000 BOE/d (based on obtaining regulatory approvals at Puskwa during 2007).

At Puskwa, a well located approximately 6.5 miles from the original discovery well was drilled and cased in Q1 2007. A second well, located 9 miles from the original discovery well is currently drilling and is expected to be finished drilling in late March or early April. Successful results from these wells have the potential to expand the pool and add significant reserves and value to Galleon. Depending upon the success of the drilling program, up to 25 wells are planned at Puskwa in the remainder of 2007 and 2008.

Galleon made significant investments in production facilities in 2006. It is expected these investments will provide Galleon with sufficient capacity to meet expected production growth in 2007. Management has established a capital budget of between $170 to $220 million for 2007.

In Q1 2007, Galleon acquired an interest in a partnership holding approximately 500 BOE/d (70% oil and 30% gas) in the Dawson area of Alberta. Approximately 30,000 net acres of undeveloped land was included. Galleon has identified significant upside in the undeveloped land for Montney gas and plans to drill up to 10 wells in the next 12 months.

Galleon is considering an asset divestiture of approximately 500 BOE/d of non-core assets in the near future.

Quarterly Highlights	2006				2005			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production								
Light oil (Bbl/d)	2,419	1,823	1,753	1,859	2,271	2,213	1,393	670
Heavy oil (Bbl/d)	2,100	1,984	1,705	1,580	1,135	1,205	594	206
Natural Gas (Mcf/d)	36,733	33,068	30,014	30,445	32,212	27,452	21,813	15,511
Liquids (Bbl/d)	230	102	100	93	99	71	21	37
BOE/d	**10,869**	**9,420**	**8,560**	**8,606**	**8,874**	**8,064**	**5,643**	**3,499**
Total BOE produced	999,982	866,646	778,992	774,578	816,420	741,917	513,535	314,887
Daily BOE of production per million Class A shares – basic[1]	**191**	**172**	**165**	**173**	**186**	**169**	**130**	**96**
Prices (net of transportation)								
Light oil ($/Bbl)	61.12	75.65	75.63	65.66	67.44	73.64	65.35	59.72
Heavy oil ($/Bbl)	31.16	47.01	42.69	24.71	29.31	48.19	32.21	26.45
Crude oil ($/Bbl)	47.19	53.35	59.39	46.78	54.73	62.54	54.86	51.91
Natural Gas ($/Mcf)	6.84	5.58	5.97	7.36	11.16	9.13	6.99	6.51
NGLs ($/Bbl)	56.02	69.83	65.71	57.62	58.84	56.64	53.94	44.75
Per BOE ($)								
Revenues	45.26	46.06	46.88	46.77	63.68	59.99	48.18	43.86
Royalties, net of ARTC & GCA	(6.02)	(7.20)	(4.34)	(10.18)	(15.01)	(11.69)	(11.11)	(10.08)
Transportation costs	(1.37)	(1.25)	(1.22)	(1.43)	(1.48)	(1.64)	(1.37)	(1.51)
Operating costs	(9.65)	(10.66)	(9.91)	(9.12)	(7.73)	(6.98)	(5.31)	(5.04)
Net	**28.22**	**26.95**	**31.41**	**26.04**	**39.46**	**39.68**	**30.39**	**27.23**
Other revenue	-	-	-	-	-	-	0.03	0.02
G&A	(2.67)	(0.80)	(1.37)	(1.50)	(1.82)	(1.58)	(2.01)	(2.38)
Interest	(1.49)	(1.39)	(1.41)	(0.95)	(0.91)	(0.90)	(1.09)	(1.33)
Capital and other taxes	(0.21)	(0.33)	(0.30)	(0.29)	(0.40)	(0.38)	(0.49)	(0.32)
Funds from operations[2]	**23.85**	**24.43**	**28.33**	**23.30**	**36.33**	**36.82**	**26.83**	**23.22**

[1]Restated to reflect a three-for-two Class A share split in June 2006.
[2]See "Non-GAAP Measurements"

END