EMBER RESOURCES

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2007

Dated March 20, 2008

TABLE OF CONTENTS

Page

ABBREVIATIONS AND CONVERSION

In this document, the abbreviations set forth below have the following meanings:

Oil, Natural Gas Liquids and Natural Gas

NGLs	natural gas liquids
Mcf	thousand cubic feet
Mmcf	million cubic feet
Mmcfe	million cubic feet of gas equivalent
Mcf/d	thousand cubic feet per day
mcfe/d	thousand cubic feet of gas equivalent per day
Mmcf/d	million cubic feet per day
MMBtu	million British Thermal Units
Bcf	billion cubic feet
Bcfe	billion cubic feet of gas equivalent on the basis of 6 mcfe to 1 BOE

Other

AECO	EnCana Corporation's natural gas storage facility located at Suffield, Alberta.
BOE	barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 1 BOE for 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead
BOE/d	barrel of oil equivalent per day
mcfe	thousand cubic feet of gas equivalent on the basis of 6 mcfe to 1 BOE
m3	cubic metres
M$	thousands of dollars
MM$	millions of dollars

Conversions

The following table sets forth certain standard conversions between Standard Imperial Units and the International system of Units (or metric units)

To convert from	To	Multiply by
mcf	cubic metres	0.028
cubic metres of gas	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres of oil	bbls	6.289
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

DEFINITIONS

The following terms have the following meanings:

"**Arrangement**" means the arrangement under the *Business Corporations Act* (Alberta) involving the Corporation, Thunder Energy Inc., Mustang Resources Inc. and Forte Resources Inc., among others.

"**associated gas**" means the gas cap overlying a crude oil accumulation in a reservoir.

"**coal bed methane**" or "**CBM**" means natural gas produced from coal formations. To produce this gas, the pressure in the coal seam must be reduced so that the gas can flow through existing fractures, called cleats, to a production well.

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook.

"**contingent resources**" as described in the COGE Handbook means those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters or a lack of markets.

"**Corporation**" or "**Ember**" means Ember Resources Inc.

"**crude oil**" or "**oil**" as described in the COGE Handbook means a mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons but does not include liquids obtained from the processing of natural gas.

"**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 the 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 and acquiring 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, to the extent necessary in developing the reserves;

(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 the 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.

"**development well**" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"**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 (sometimes referred to in part as "prospecting costs") 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 (collectively sometimes referred to as "geological and geophysical costs");

(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.

"**exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well.

"**field**" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to denote localized geological features, in contrast to broader terms such as "basin", "trend", "province", "play" or "area of interest".

"**forecast prices and costs**" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future;

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

"**future income tax expenses**" means future income tax expenses estimated (generally, year-by-year):

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;

(b) without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances (for example, royalty tax credits); and

(d) applying to the future pre-tax net cash flows relating to the reporting issuer's oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

"**future net revenue**" means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, CBM and other non-conventional reserves) estimated using forecast prices and costs.

"**gross**" means:

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

"**natural gas**" as described in the COGE Handbook means a mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds.

"**natural gas liquids**" as described in the COGE Handbook means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

"**net**" means

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

(b) in relation to the Corporation's interest in 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.

"**non-associated gas**" means an accumulation of natural gas in a reservoir where there is no crude oil.

"**operating costs**" or "**production costs**" means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

"**production**" means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

"**property**" includes:

(a) fee ownership or a lease, concession, agreement, permit, licence or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;

(b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and

(c) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

"**property acquisition costs**" means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:

(a) costs of lease bonuses and options to purchase or lease a property;

(b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee;

(c) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

"**proved property**" means a property or part of a property to which reserves have been specifically attributed.

"**reservoir**" means a porous and permeable subsurface rock formation that contains a separate accumulation of petroleum that is confined by impermeable rock or water barriers and is characterized by a single pressure system.

"**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.

"**solution gas**" means natural gas dissolved in crude oil.

"**stratigraphic test well**" means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (a) "exploratory type" if not drilled into a proved property; or (b) "development type", if drilled into a proved property. Development type stratigraphic wells are also referred to as "evaluation wells".

"**support equipment and facilities**" means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

"**unproved property**" means a property or part of a property to which no reserves have been specifically attributed.

"**well abandonment costs**" means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. They do not include costs of abandoning the gathering system or reclaiming the wellsite.

RESERVES DEFINITIONS

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

"**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: (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.

"**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.

"**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.

"**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.

"**Undeveloped**" reserves are those reserves expected to be recovered from know accumulations where a significant expenditure (e.g., 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, possible) 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 sub-divide 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.

"**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.

"**Possible**" reserves are those additional reserves that are less certain to be recovered than Probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated Proved plus Probable plus Possible reserves.

FORWARD-LOOKING STATEMENTS

Some of the statements contained herein including, without limitation, financial and business prospects and financial outlooks, 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 and other risk factors. 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, except as required by law, Ember assumes no obligation to update or revise them to reflect new events or circumstances.

Forward-looking statements and other information contained herein concerning the oil and gas industry and Ember's general expectations concerning this industry are 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 Ember believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While Ember 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.

In particular, this annual information form contains forward-looking information pertaining to the following:

- the quantity of and future net revenues from Ember's reserves;
- natural gas production levels;
- commodity prices, foreign currency exchange rates and interest rates;
- capital expenditure programs and other expenditures;
- supply and demand for natural gas;
- expectations regarding Ember's ability to raise capital and to continually add to reserves through acquisitions and development;
- schedules and timing of certain projects and Ember's strategy for growth;
- competitive conditions;
- Ember's future operating and financial results; and
- treatment under governmental and other regulatory regimes and tax, environmental and other laws.

Ember's actual results could differ materially from those anticipated in these forward-looking information as a result of both known and unknown risks, including the risk factors set forth under "Risk Factors" and those set forth below:

- volatility in market prices for oil, NGLs and natural gas;
- changes or fluctuations in oil, NGLs and natural gas production levels;
- changes in foreign currency exchange rates and interest rates;
- changes in capital and other expenditure requirements and debt service requirements;

- liabilities and unexpected events inherent in oil and gas operations, including geological, technical, drilling and processing problems;
- uncertainties associated with estimating reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- Ember's success at acquisition, exploitation and development of reserves;
- changes in general economic, market and business conditions in Canada, North America and worldwide; and
- changes in environmental or other legislation applicable to Ember's operation's and Ember's ability to comply with current and future environmental and other laws.

EMBER RESOURCES INC.

Ember Resources Inc. was incorporated under the *Business Corporations Act* (Alberta) on June 3, 2005.

Ember is a publicly traded oil and gas company engaged in the exploration for, and the acquisition, development and production of, natural gas reserves, derived primarily from CBM. Ember is a reporting issuer or the equivalent thereof in the provinces of British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Québec, Nova Scotia, Prince Edward Island and Newfoundland and its common shares are listed and posted for trading on the Toronto Stock Exchange (the "TSX") under the trading symbol "EBR". Ember was formed in 2005 for the purpose of acquiring and developing the CBM interests of Thunder Energy Inc. ("Thunder").

The head and principal office of Ember is located at Suite 800, 521 – 3rd Avenue S.W., Calgary, Alberta and its registered office is located at Suite 3700, 400 – 3rd Avenue S.W., Calgary, Alberta.

DEVELOPMENT OF THE BUSINESS OF EMBER

History

In July 2005, Thunder, Mustang Resources Inc. ("Mustang") and Forte Resources Inc. ("Forte") completed the Arrangement. Under the Arrangement, Ember acquired certain natural gas rights associated with coal from Thunder and became engaged in the acquisition, development and production of CBM gas reserves. Ember assumed all liabilities, including environmental liabilities, relating to the transferred assets.

In July 2005, Ember completed a $6 million private placement consisting of 3,108,808 common shares in the capital of Ember ("Common Shares") issued at $1.93 per share to employees, directors and service providers of Ember. The Common Shares were subject to escrow with one-third of such shares having been released from escrow on each of January 9, 2006, July 10, 2006 and July 5, 2007. See "Prior Sales".

In July 2005, Ember issued 1,400,000 non-voting performance shares without nominal or par value to Ember service providers at a price of $0.01 per share (the "Ember Performance Shares"). Each performance share is convertible into a fraction of an Ember Share equal to the closing price on the TSX on the trading day prior to conversion less $1.93, divided by the closing price of an Ember Share on the trading day prior to conversion. The Ember Performance Shares will vest and become convertible into Common Shares equally on each of the first, second and third anniversaries from the date of grant if the holder is an Ember service provider on such date. Pursuant to the terms of the Ember Performance Shares, upon a service provider ceasing to be a service provider such shares are to be redeemed.

On July 7, 2005, Ember entered into an agreement with a Canadian chartered bank for the provision of credit facilities in the amount of $2.5 million. The credit facilities bear interest at the price rate plus an applicable margin. The credit facilities are secured by a charge over all of the assets of Ember.

On August 31, 2005, Ember completed a bought deal financing of 7,000,000 Common Shares at a price of $7.15 per share for gross proceeds of $50,050,000. See "Prior Sales".

In April 2006, Ember finalized arrangements to increase its credit facility to $15 million from $2.5 million. The facility was renewed in October 2006.

On October 18, 2006, the Company held a Special Meeting of Shareholders in which the shareholders ratified and approved the Shareholder Rights Plan of Ember which was adopted pursuant to a Shareholder Rights Agreement dated August 9, 2006 between Ember and Olympia Trust Company, as rights agent.

On March 1, 2007, Ember completed the acquisition of certain CBM assets in the Acme area of Alberta from a private Alberta based company for $8.75 million (the "Acme Acquisition").

Concurrent with the completion of the Acme Acquisition, Ember completed a private placement to a Calgary based private equity firm of 5,660,400 Common Shares at a purchase price of $2.65 per share. Total proceeds of $15 million were used to complete the Acme Acquisition, with the balance of $6.25 million used to expand Ember's capital program for 2007.

In May 2007, Ember finalized arrangements to increase its credit facility to a total of $25 million. The facility was renewed in October 2007 with the next review scheduled for April 2008.

Recent Developments

In late October 2007, the Alberta government announced changes to royalties paid to the province to be effective on January 1, 2009. The province has identified non-conventional resources, such as CBM and the oil sands, as future industries for Alberta and changes to the royalty structure are designed to encourage further development.

Ember's average well productivity included in its reserve report is estimated at 50 Mcf/d. Based on the proposed changes, royalties paid to the Alberta government will decline from a base rate of 9% in 2008 to 5% in 2009 and beyond. The 5% royalty rate would remain in effect at prices up to $9.80/Mcf. At $11.50/Mcf the royalty rate would increase to the original 9%. As a result, Ember is expected to benefit immediately from the proposed changes and will continue to benefit in a higher gas price environment. A sensitivity case was run on the year 2007 year end reserves that resulted in an overall increase of $5.6 million (5.8%) in Ember's share of before tax net present value (Proved plus Probable discounted at 10%).

Ember believes that two other changes will have long-term benefits to the Corporation and the CBM industry. Firstly, an incentive was introduced for gas wells with total measured depths in excess of 2,000 metres. Typical single-leg horizontal Mannville wells have measured depths of 2,000–2,500 metres. The second initiative is "shallow rights reversion" which will require shallow zones, such as the Horseshoe Canyon coals, to revert back to the Crown for resale when the existing lease is held by deeper production.

Trends

Soft gas prices through much of 2006 and 2007 have caused a contraction of capital programs on an industry wide basis in Canada, resulting in emerging gas supply challenges. Gas production levels in the Western Canadian Sedimentary Basin are down one Bcf per day from levels one year ago. There are expectations that further production declines could occur through 2008. This coupled with storage reductions from a fairly cold January and February of 2008 in North America had created conditions for the potential of a continuing price rally through 2008. Factors which will have an immediate impact on gas prices are: the supply demand balance in North America, imports of LNG, demand destruction, weather patterns, drilling trends in both Canada and the US and overall economic activity.

CBM is in all material respects the same as natural gas. It varies in heating content and other elements contained within the produced gas stream. For example, Ember's CBM contains no harmful H_2S and minor amounts of CO_2. Ember currently receives pricing that averages approximately 2% to 5% less than the weighted average of AECO (based on Ember's weighted average volumes) in Canadian dollars which reflects the slightly lower heating content of CBM gas. Traditionally Ember's gas has a heat content that commands a price of approximately 2% under AECO. Recent production additions from new wells in the Company's Acme area are experiencing lower heating values due to the recovery of nitrogen used in the completion process. This has caused Ember's current pricing in the short term to be approximately 4% to

5% under AECO. As heating values return to normal in the next several months, once all nitrogen is recovered on new wells, Ember's pricing structure should return closer to 2% under AECO.

DESCRIPTION OF THE BUSINESS OF EMBER

General

Ember is engaged in the exploration for, and the acquisition, development and production of, natural gas reserves derived primarily from CBM. Ember currently has four core properties, located in Alberta. Ember established its core positions with an initial acquisition of producing and non-producing assets transferred to it pursuant to the Arrangement. The Corporation added to this base of assets with an acquisition of property in the Acme area in March 2007 (see "Statement of Reserves Data and Other Oil and Gas Information - Principal Properties"). With the opportunity base established, Ember has expanded production and land positions with workovers, drilling, complimentary acquisitions and new land purchases.

Corporate Strategy

Ember's business objective is to exploit the production and growth potential inherent in its CBM assets. Ember's focus is on the partially developed Horseshoe Canyon play at Fenn Big Valley, its recently acquired Acme property, and its larger Mannville CBM play which consists of Mannville coal seams at Rosalind, Manola and Fenn Big Valley. Ember's Mannville projects in these areas are on trend with and are contiguous to other industry activity in the area. Ember has and will pursue complementary land acquisitions in its core areas.

Revenues

For the year ended December 31, 2007, 98% of Ember's revenue before royalties was derived from CBM natural gas production from the Horseshoe Canyon play at Fenn Big Valley and Acme

CBM

CBM is natural gas, predominately methane gas, which occurs in coal seams. The gas can be produced economically by drilling conventional style vertical and horizontal gas wells and employing special completion techniques which are specific to this type of reservoir. CBM is virtually identical to the sweet gas produced from conventional sandstone reservoirs. In Alberta, CBM is subject to the same drilling, production and operational rules as other forms of sweet natural gas.

CBM reservoir characteristics differ fundamentally from those of conventional petroleum reservoirs. In CBM reservoirs, gas molecules are attached, or adsorbed, to the coal matrix. As the pressure in the coal seam is depleted, the gas molecules detach, or desorb, from the coal surface and diffuse through the matrix until they reach a natural fracture called a cleat. The gas molecules then flow through the natural fracture system to the wellbore. The composition and geological history of a coal seam will determine whether it is saturated with gas or whether it exists in some state of undersaturation. In an undersaturated coal seam only water is produced initially, with gas production being delayed until reservoir pressure has declined to the point of saturation (critical gas desorption pressure).

Ultimate gas recovery from a CBM well is a function of a complex relationship between permeability, thickness, coalbed gas content and well spacing, but the production rates for the first portion of the well's economic life are almost solely dependent on the coal seam permeability and gas content.

De-methanization, the removal of methane gas from coalbeds undergoing mining, has been carried out since World War II utilizing underground collection systems and boreholes drilled from the surface.

During the 1980s in the United States, oil field completion and stimulation techniques were applied to wells drilled from the surface resulting in profitable gas wells. This exploration and development technology is now being actively applied in, among others, Canada, Australia, India, China and the United Kingdom.

Until the early 1980s, the natural gas industry considered CBM to be a coal mining industry problem. It was a nuisance and hazard to coal mining as opposed to a potential source of natural gas. Even though coal is a source rock for conventional reservoirs, coal seams were not considered as completion targets because they often had little or no gas shows and it was not considered probable that a thin, shallow horizon could hold economic quantities of gas. It took an understanding of the storage and production mechanisms, and modification of conventional oil and gas technology, before CBM became recognized as an important source of economic gas supplies.

Coal is unusual as a reservoir because it is both the source rock and the reservoir for the gas. Gas is stored in an adsorbed state on coal, and thus for a given reservoir pressure much more gas can be stored in a coal seam than in a comparable sandstone reservoir. The methane recovered from coal seams is virtually the same as sweet natural gas which is produced from conventional sandstone reservoirs, and therefore should have the same marketability and demand the same price.

Production of gas from coal seams is controlled by a three step process. First, the gas is desorbed from the coal. It then diffuses through the coal matrix to the cleat system. Coals contain small (typically, several per centimetre), regularly spaced, naturally occurring fractures called face and butt cleats. Finally, the gas flows through the fracture and cleat system to the well bore.

Many coal reservoirs are water saturated, and water maintains the reservoir pressure that holds the gas in the adsorbed state in the coals. Typically, water must be produced from coal seams to reduce the reservoir pressure and release the gas.

The reservoir properties which most affect CBM recovery are net coal thickness, gas content, permeability and the desorption and diffusion characteristics of the coal. Well log, core data and laboratory studies are necessary to determine these parameters. Although some of this data is in the public domain, it is very disparate on a regional basis, and as such usually needs to be gathered from new samples.

As the reservoir pressure drops from the critical desorption pressure to the abandonment pressure, the amount of gas that the coal can store also decreases. This difference in storage capacities represents the amount of gas that can desorb and become available for production.

For a successful CBM project, producers must accurately characterize the reservoir properties and apply the available technology to optimize production.

In situ CBM resources are estimated by applying industry standard reserve calculations. It must be noted that resource estimates have inherent errors due to the method of measurement, and the effect of moisture change, non organic content, lost gas on core extraction and other error sources.

Management believes that the most promising formations for the recovery of CBM in Western Canada are the Horseshoe Canyon and the Upper and Lower Mannville coals located in a fairway from south of Calgary to north of Edmonton, Alberta. However, there are numerous other gas bearing coal formations that may become economic resources.

To achieve an economical recovery, a coal must contain sufficient gas. The required combination of permeability and methane generation and storage occur in coals ranked between medium volatile and low volatile bituminous. Coal seams that have been targeted for CBM development usually have a rank between high volatile bituminous and medium volatile bituminous. Coal rank and gas content generally increase with depth, but increased depth can have a detrimental effect on permeability. Therefore, there is a trade off between increased gas content and diminishing permeability.

A satisfactory reservoir is one requirement to economic recovery of CBM resources. An entity must also develop successful drilling and completion techniques in order to depressure the coals and ultimately produce the associated gas. These techniques are and may be varied and their application will vary among different types of coal.

Coal gas capacity is also reduced by the effect of ash (typically 5% to 30%) and increasing temperatures. Ash is an all encompassing term for mineral impurities; more impurities in the coal means fewer adsorption sites for methane molecules. Increasing coal seam temperature also reduces gas capacity in that the energy in the methane molecules causes the gas not to adsorb. The actual gas content of many coal seams can be less than the potential gas capacity. This can result from post depositional uplifting, faulting and erosion. Uplifting can reduce the coal's temperature and increase its gas capacity, hence producing an undersaturated coal. Faulting and erosion can allow gas to escape throughout geologic history and again lead to an undersaturated coal. As noted previously, in an undersaturated coal seam, pressure must be depleted past critical desorption pressure. The gas production is delayed until the reservoir pressure has declined to the level of saturation.

Competition

The oil and natural gas industry is competitive in all its phases. Ember competes with numerous other participants in the search for, and the acquisition of, natural gas properties and in the marketing of natural gas. Ember's competitors include resource companies which have greater financial resources, staff and facilities than those of Ember. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Ember views its competitive position as being equivalent to that of other oil and gas issuers of similar size and at a similar stage of development.

Seasonal Factors

The exploration for and development of oil and natural gas reserves is dependent on access to areas where production is to be conducted. Ember carries on operations where all properties have year-round access, however, seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation can require significant expenditures or result in operational restrictions. 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, all of which might have a significant negative impact on earnings and overall competitiveness. Ember believes that it is in material compliance with applicable environmental laws and regulations. Ember anticipates making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment. Ember also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

Personnel

As at December 31, 2007, Ember had in its head office in Calgary 21 employees and 0.25 consultants.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Principal Properties

A summary description of Ember's major producing and exploration properties is set out below. References to gross volumes refer to total production. References to net volumes refer to Ember's working interest share before the deduction of royalties payable to others.

Fenn Big Valley, Alberta

The Fenn Big Valley properties are predominantly Horseshoe Canyon properties and are located approximately 140 kilometres northeast of the City of Calgary and include an average working interest of 93% in 54,470 gross (50,625 net) acres of land in this area. There are 148 (141.3 net) CBM wells in the Fenn Big Valley area, of which there were 143 (138.3 net) producing CBM wells as of December 31, 2007. Ember owns 7 Mmcf/d of processing capacity in two natural gas plants and interests in a gathering system that covers four townships in the area. Production in Fenn Big Valley for the period ended December 31, 2007 averaged 5,255 Mcf/d or 876 BOE/d.

In 2006, Ember entered into operating agreements with Thunder Energy Trust, now Sword Energy Inc. ("Sword"), which govern the parties' respective rights and obligations with respect to certain dual producing wells on the Fenn Big Valley properties. The agreements provide for producing Sword's conventional gas and Ember's CBM through the same well bore. The agreements also address well abandonments and the administration of well licenses and provide Ember with the right to take-over non-productive conventional wells for CBM production in certain circumstances.

During the year ended December 31, 2007, 17 (14.8 net) wells were drilled in the area to a depth of approximately 1000 metres, resulting in 16 (13.8 net) CBM wells.

Planned development activity in the Fenn Big Valley area for 2008 includes the drilling of up to 10 (10 net) CBM wells.

Acme, Alberta

The Acme properties located approximately 80 kilometres northeast of the City of Calgary are being developed in Horseshoe Canyon Coals and include an average working interest of 70% in 16,906 gross (11,933 net) acres of land in this area. Ember completed the acquisition of this property on March 1, 2007. There are 33 (29.9 net) CBM wells in the Acme area, of which there were 31 (29.1 net) producing CBM wells as of December 31, 2007. Production in Acme which commenced November, 2007 averaged 356 Mcf/d or 59 boed for the year ended December 31, 2007. Acme production for the month of December 2007 averaged 2,895 Mcf/d or 483 BOE/d.

In May 2007, a long-term processing agreement for Ember's newly acquired Acme property was signed with Ember's partner Altagas Operating Partnership ("AltaGas"). Under the agreement, Altagas agreed to construct all of the required processing and pipeline infrastructure; in return Ember will pay a processing fee and dedicate its gas production and reserves in the area to the facility. The agreement commits Ember to deliver a minimum of 16.8 bcf of gas over an estimated six year period. Total cost to construct the infrastructure was approximately $12 million.

During the year ended December 31, 2007, 23 (21.5 net) wells were drilled in the area at a depth of approximately 1050 metres. In addition, the Corporation tied-in 8 (7.6 net) wells that were acquired in the original acquisition of the Acme area.

Planned development activity in the Acme area for 2008 includes the drilling of up to 55 (30 net) CBM wells.

Rosalind, Alberta

The Rosalind properties are prospective for Mannville coals and are located approximately 140 kilometres southeast of the City of Edmonton. The properties have multi zone potential for CBM, including the Mannville and Belly River zones and include an average working interest of 81% in 113,289 gross (92,021 net) acres of land in this area. There are a total of 14 (8.0 net) CBM wells in the Rosalind area, of which 4 (2.0 net) are producing CBM wells. In addition, there are 10 (5.5 net) CBM wells under observation on the properties. Ember has access to two non-operated gas plants in the area on a fee basis. Production in Rosalind for the year ended December 31, 2007 averaged 71 Mcf/d or 12 BOE/d.

During the year ended December 31, 2007, no wells were drilled in the area.

Ember plans to continue with the development in the Rosalind area. For 2008, there are currently no plans to drill any wells, however, the Corporation is seeking partners to assist in further development.

Manola, Alberta

The Manola properties are prospective for Mannville coals and are located approximately 150 kilometres northwest of the City of Edmonton and include an average working interest of 98% in 102,400 gross (100,786 net) acres of land in this area. Presently, there are a total of 15 (15 net) CBM wells in the Manola area, of which there are 4 (4 net) producing CBM wells, 10 (10 net) CBM development wells under observation on the properties and 1 (1 net) injection well. Ember has access to facility infrastructure to gather and process its gas on a processing fee basis. Production in Manola for the year ended December 31, 2007 averaged 147 Mcf/d or 24 BOE/d.

During the year ended December 31, 2007, 1 (1 net) horizontal well was drilled in the area at a depth of approximately 950 metres, resulting in 1 (1 net) CBM well.

Ember plans to continue with the development in the Manola area. For 2008, there are presently no plans to drill any wells, however, the Corporation is seeking partners to assist in further development.

Other

In addition to its four core properties, Ember owns an interest in an additional property located at Matziwin, Alberta. The Matziwin properties are located approximately 140 kilometres east of the City of Calgary and include an average working interest of 91% in 32,320 gross (29,379 net) acres of land in this area. There are currently no CBM wells on the properties and none are planned to be drilled during 2008.

Reserves Data

In accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"), Sproule Associates Limited ("Sproule") prepared a report (the "Sproule Report") dated March 4, 2008. The Sproule Report combined the evaluation completed by Sproule of the Fenn, Manola and Rosalind properties and the evaluation completed by McDaniel & Associates Consultants Ltd. ("McDaniel") of the Acme property, as at December 31, 2007, of Ember's oil, NGL and natural gas reserves. The tables below are a summary of the oil, NGL and natural gas reserves of the Corporation and the net present value of future net revenue attributable to such reserves as summarized in the Sproule Report based on forecast price and cost assumptions. The tables summarize the data contained in the

Sproule Report and as a result may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to the Corporation's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by Sproule and McDaniel. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Corporation's reserves estimated by Sproule and McDaniel represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of the Corporation's oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The values shown for income taxes and future net revenue after income taxes were calculated on a stand-alone basis in the Sproule Report. The values shown may not be representative of future income tax obligations, applicable tax horizon or after tax valuation.

The Sproule Report is based on certain factual data supplied by the Corporation and Sproule's and McDaniel's opinions of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Corporation's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Corporation to Sproule and McDaniel and accepted without any further investigation. Sproule and McDaniel accepted this data as presented and neither title searches nor field inspections were conducted.

Reserves Data – Forecast Prices and Costs

Summary of Oil and Gas Reserves as of December 31, 2007 – Forecast Prices and Costs

	Natural Gas	
	Gross CBM(1)	Net CBM(1)
RESERVES CATEGORY	(Bcf)	(Bcf)
Proved		
Developed Producing	14.5	12.9
Developed Non-Producing	0.4	0.3
Undeveloped	16.4	13.6
Total Proved	31.3	26.9
Probable	20.0	17.2
Total Proved plus Probable	51.3	44.1
Possible	8.1	6.9
Total Proved Plus Probable plus Possible	59.3	51.0

Note:

(1) Including conventional gas and by-products, but excluding solution gas from oil wells. Conventional gas and by-products are included in CBM, as they are immaterial.

Summary of Net Present Value of Future Net Revenue as of December 31, 2007 – Forecast Prices and Costs

	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year)					Unit Value Before Income Tax Deducted at 10%/year
	0	5	10	15	20	0	5	10	15	20	($/BOE)
RESERVES CATEGORY	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	
Proved											
Developed Producing	66.4	56.0	48.2	42.3	37.7	66.4	56.0	48.2	42.3	37.7	22.42
Developed Non-Producing	1.6	1.3	1.1	0.9	0.8	1.6	1.3	1.1	0.9	0.8	20.16
Undeveloped	43.3	28.5	18.6	11.8	7.0	43.3	28.5	18.6	11.8	7.0	8.18
Total Proved	111.4	85.8	67.9	55.0	45.5	111.4	85.8	67.9	55.0	45.5	15.17
Probable	74.4	46.1	29.3	18.9	12.2	60.1	37.7	24.2	15.7	10.2	10.22
Total Proved plus Probable	185.5	131.9	97.2	73.9	57.8	171.5	123.5	92.1	70.7	55.7	13.24
Possible	35.8	20.4	12.3	7.8	5.1	27.2	15.5	9.4	5.9	3.9	10.68
Total Proved Plus Probable plus Possible	221.6	152.3	109.5	81.7	62.9	198.8	139.0	101.5	76.7	59.5	12.89

Total Future Net Revenue (Undiscounted) as of December 31, 2007 – Forecast Prices

	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
RESERVES CATEGORY	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)
Proved Reserves	240.0	29.3	63.7	29.5	6.1	111.4	0	111.4
Proved plus Probable Reserves	404.3	48.8	109.7	51.1	8.8	185.8	14.3	171.5
Proved plus Probable plus Possible Reserves	474.8	57.6	130.1	55.9	9.6	221.6	22.8	198.8

Future Net Revenue by Production Group as of December 31, 2007 - Forecast Prices

	Future Net Revenue Before Income Taxes (discounted at 10%/year)	Unit Value Before Income Tax Deducted at 10%/year
RESERVES CATEGORY	(MM$)	($/BOE)
Proved Reserves		
CBM[(1)]	67.9	15.17
Proved plus Probable Reserves		
CBM[(1)]	97.2	13.24
Proved plus Probable plus Possible Reserves		
CBM[(1)]	109.5	12.89

Notes:

(1) Including conventional gas and by-products, but excluding solution gas from oil wells. Conventional gas and by-products are included in CBM, as they are immaterial.

(2) Unit Values are based on net reserve volumes.

Summary of Pricing Assumptions and Inflation Rate Assumptions as of December 31, 2007 – Forecast Prices and Costs

Sproule employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2007 in estimating Ember's reserves data using forecast prices and costs:

	Natural Gas		Inflation Rates	Exchange Rate
Year	Henry Hub ($US/MMBtu)	AECO Gas Price ($Cdn/MMBtu)	%/year	($US/$Cdn)
Forecast				
2008	7.56	6.51	2.0	1.0
2009	8.27	7.22	2.0	1.0
2010	8.74	7.69	2.0	1.0
2011	8.75	7.70	2.0	1.0
2012	8.66	7.61	2.0	1.0
2013	8.83	7.78	2.0	1.0
2014	9.01	7.96	2.0	1.0
2015	9.19	8.14	2.0	1.0
2016	9.37	8.32	2.0	1.0
2017	9.56	8.51	2.0	1.0
Thereafter escalation rate of 2%.				

The weighted average realized sales price for Ember for the year ended December 31, 2007 was $6.27/Mcf for natural gas.

Reconciliation of Corporation Gross[(1)] Reserves by Product Type – Forecast Prices and Costs

The following table sets forth the changes between the Corporation's reserve volume estimates made as at December 31, 2007 and the corresponding estimates as at December 31, 2006, based on forecast prices:

	Associated and Non-Associated Gas		
Factors	Gross Proved CBM[(2)]	Gross Probable CBM[(2)]	Gross Proved Plus Probable CBM[(2)]
	(MMcf)	(MMcf)	(MMcf)
December 31, 2006	15,026	27,402	40,609
Extension & Improved Recovery	2,143	3,467	3,720
Technical Revisions	1,990	(5,005)	(16,577)
Discoveries	-	-	-
Acquisitions	14,153	27,434	33,611
Dispositions	-	-	-
Economic Factors	(1)	(22)	(24)
Production	(2,000)	(2,000)	(2,000)
December 31, 2007	31,311	51,275	59,338

Notes:

(1) "Gross" means the Corporation's working interest reserves before calculation of royalties and before consideration of the Corporation's royalty interests.

(2) Including conventional gas and by-products, but excluding solution gas from oil wells. Conventional gas is included in CBM, as it is immaterial.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is 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. Ember's reserves are evaluated by Sproule and McDaniel, independent engineering firms.

As circumstances change and additional data become available, reserve estimates also change. Estimates made 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 governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

Future Development Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to Proved reserves, Proved plus Probable reserves and Proved plus Probable plus Possible reserves (using forecast prices and costs only):

	Total Proved Reserves	Proved Plus Probable Reserves	Proved Plus Probable Plus Possible Reserves
	(M$)	(M$)	(M$)
2008	8,328	17,196	18,646
2009	15,800	18,102	18,225
2010	5,389	15,856	18,995
2011	-	-	-
Remaining Years	-	-	-
Total Undiscounted	29,518	51,154	55,866

Ember estimates that its internally generated cash flow will be sufficient to fund the future development costs disclosed above. Ember typically has available three sources of funding to finance its capital expenditure program; internally generated cash flow from operations, new equity issues, if available on favourable terms, and debt financing when appropriate. Debt financing is available to Ember at the Bank of Montreal prime lending rate plus an applicable margin (dependant upon debt to trailing cash flow).

Ember expects to fund its total 2008 capital program with proceeds from recent and potential future equity issues and internally generated cash flow and, although quarterly fluctuations in funding levels are expected, the objective is to remain within the Corporation's debt capacity throughout the 2008 financial year. Ember's objective is to reduce its debt to cash flow ratio to less than 1.5 times estimated future cash flows.

Contingent Resources

In addition to conducting an independent reserves evaluation, Sproule was retained by Ember to complete an independent estimate of Ember's contingent CBM resources for the undeveloped lands that Ember owns. These resources are categorized by Sproule as contingent resources which are defined in the COGE Handbook. This definition states that contingent resources are not currently economic. Ember believes that these contingent resources are not known to be economic at this time, rather than not economic. The contingencies that result in CBM being classified as a contingent resource include but are not limited to capital costs, operating costs, deliverability, future gas prices and project timing. There is no certainty that it will be technically or economically viable to produce any portion of the reported contingent resource.

Mannville Coals

Original gas-in-place ("OGIP") for each section was estimated volumetrically using net pay estimated from existing logs. Gas contents specific to each area were then applied to provide OGIP estimates. Variations in the assignment of OGIP in the low, best and high cases were based on the inclusion of individual coal seams, as follows:

- The low case OGIP calculation includes the net pay in the major seam of an area of potential development. The recovery factor is then estimated based on engineering judgment for each area. The recovery factors assigned in the low case range from 5% to 25%.

- The best case OGIP calculation considers the net pay from the major and secondary coal seams where the secondary coal seam was greater than 0.9 metres in thickness. The recovery factors assigned in the best case range from 20% to 35%.

- The high case OGIP calculation includes all coals seams greater than 0.9m in thickness. The recovery factors assigned in the high case range from 40% to 50%.

Sproule then estimates contingent resources based on calculated OGIP and assigned recovery factors.

The following table summarizes Sproule's contingent resource estimates attributable to Ember's properties as at December 31, 2007:

	Company Interest Original Gas in Place (Bcf Raw)			Company Interest Technically Recoverable Sales Gas (Bcf Sales)		
Area / Prospect	Low Case	Best Case	High Case	Low Case	Best Case	High Case
Manville Coals						
Fenn Big Valley	33.7	57.1	77.9	1.6	10.8	29.6
Manola	215.2	343.9	427.2	50.0	112.0	198.7
Rosalind	196.6	309.2	418.8	36.6	86.4	195.1
Total	445.5	710.2	923.9	88.3	209.2	423.3

The following table summarizes the expiries of land in the Mannville coal contingent resource in Ember's three operating areas. A total of 115,516 net acres of undeveloped land will reach the end of its primary term within 5 years. This represents 58% of Ember's total undeveloped land in the Mannville coals in the three areas (198,781 net acres). The balance of Ember's undeveloped lands in the Mannville coal in the three areas is continued.

	Rosalind		Fenn Big Valley		Manola		Total	
Expires by Year:	Gross Undeveloped (acres)	Net Undeveloped (acres)	Gross Undeveloped (acres)	Net Undeveloped (acres)	Gross Undeveloped (acres)	Net Undeveloped (acres)	Gross Undeveloped (acres)	Net Undeveloped (acres)
2008	18,008	14,036	6,240	6,240	24,000	24,000	48,248	44,276
2009	4,762	4,504	640	640	16,000	16,000	21,402	21,144
2010	24,176	24,176	960	960	13,440	13,440	38,576	38,576
2011	1,280	1,280	0	0	8,960	8,960	10,240	10,240
2012	1,280	1,280	0	0	0	0	1,280	1,280
Totals	49,506	45,276	7,840	7,840	62,400	62,400	119,746	115,516

CBM development at Corbett Creek (located approximately 40 kilometers northwest of Ember's Manola property), operated by Trident Exploration Corp. and Nexen Inc., is currently the only commercial project in Alberta producing CBM gas from the Mannville coal. Current production in the Corbett areas is above

85 Mmcf/d from approximately 150 wells. The Corbett Creek project represents the nearest analogous project with commercial production to all of Ember's Mannville coal CBM properties. Other operators are currently conducting drilling and completion operations in attempts to produce gas from the Mannville Coals, in and around Manola, Fenn Big Valley and Rosalind.

The vertical depths of Ember's Mannville CBM contingent resources are approximately 925 meters at Manola, 1075 meters at Rosalind and 1250 meters at Fenn Big Valley.

The estimated cost to drill, complete and equip a horizontal well in the Mannville coal is approximately $1,500,000.

To date, Ember has conducted extensive appraisal drilling and testing on selected lands in the Mannville coal, and established reservoir parameters condusive to commercial development. However, Ember has encountered difficulty in establishing successful well repeatability primarily due to wellbore damage caused by the drilling process. Work will continue to test different drilling and completion techniques in order to establish the required repeatability. Currently, Ember does not have plans to drill any wells in the Mannville coals in 2008 due to low gas prices and poor capital markets, however if these factors change then drilling plans may be accelerated. Pending the establishment of commercial repeatability, Ember expects to develop the contingent resources in all three areas during the next 5 to 20 years.

Ember's lands are reasonably close to pipelines and facilities owned by Ember, other operators or distribution companies. Ember will consider the appropriate transportation and marketing strategy at the time of development of the Mannville coal contingent resources in the three operating areas. At this time, Ember does not believe the marketing of the potential gas volumes will be a concern.

In management's opinion it is too early to estimate the chance of success for the appraisal programs of the Mannville coal contingent resources. By NI 51-101 definitions, these resources do not have the certainty at this time to be classified as reserves. For this reason, the evaluation conducted by Sproule presents a range of technically recoverable resources for each area. While it appears that production is possible from these formations and the gas-in-place can be reasonably estimated, the production rates and recoveries are still undetermined and have, therefore, been estimated as low, best and high contingent resources as presented in the Sproule evaluation.

Wells

The following table sets forth the number and status of CBM wells in which Ember has a working interest as at December 31, 2007:

	Producing Wells		Non-Producing Wells	
	Gross	Net	Gross	Net
Fenn Big Valley	143.0	138.2	5.0	3.0
Acme	31.0	29.1	2.0	0.75
Rosalind	4.0	2.0	10.0	6.0
Manola	4.0	4.0	11.0	11.0
Total	182.0	173.4	28.0	20.75

Properties With No Attributed Reserves

The following table summarizes the undeveloped gross and net acres of properties in which Ember has an interest and also the number of net acres for which Ember's rights to explore, develop or exploit will, absent further action, expire within one year:

	Gross Acres	Net Acres	Net Acres Expiring Within One Year
Fenn Big Valley	25,669	23,065	6,240
Acme	10,506	6,605	0
Rosalind	110,729	90,421	14,036
Manola	99,840	98,226	24,000
Matziwin	32,320	29,379	5,120
Total	279,064	247,697	49,396

Exploration and Drilling Activity

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

	Development Wells	
	Gross	Net
Mannville		
Manola	1.0	1.0
Rosalind	-	-
Horseshoe Canyon		
Fenn Big Valley	17.0	14.8
Acme	23.0	21.5
Total	41.0	37.3

Additional Information Concerning Abandonment and Reclamation Costs

Ember typically estimates well abandonment costs area by area. Such costs are included in the Sproule Report as deductions in arriving at future net revenue.

The expected total abandonment and disconnect costs included in the Sproule Report for 259 net wells under the Proved reserves category is $6,108,000 undiscounted ($1,582,000 discounted at 10%), of which a total of $127,000 is estimated to be incurred in 2008, 2009 and 2010. This estimate does not include expected reclamation and salvage costs for surface leases of $4,921,000 undiscounted.

Ember will be liable for its share of ongoing environmental obligations and for the ultimate reclamation of the properties held by it upon abandonment. Ongoing environmental obligations are expected to be funded out of cash flow.

Tax Horizon

Based on production from existing reserves, Ember estimates that it will not be required to pay income taxes for the next several years.

Costs Incurred

The following table summarizes capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) incurred by Ember for the year ended December 31, 2007:

	Property Acquisition Costs			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
Total (M$)	8,633	337	-	21,833

Production Estimates

The following table discloses for each product type the total volume of production estimated for the first year reflected in the estimates of gross proved reserves and gross probable reserves as disclosed above under the heading "Reserve Data - Forecast Prices and Costs":

	mcfe/d	BOE/d	%
CBM	8,990	1,498	100
NGL	-	-	-
	8,990	1,498	100

Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2007, certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback:

Average Daily Production Volume

	Three Months Ended			
	March 31, 2007	June 30, 2007	September 30, 2007	December 31, 2007
Natural gas (Mcf/d)	5,890	5,068	5,174	6,107
Total (BOE/d)	982	845	862	1,018

Prices Received, Royalties Paid, Production Costs and Netback – Natural Gas

($ per Mcf)	Three Months Ended			
	March 31, 2007	June 30, 2007	September 30, 2007	December 31, 2007
Prices Received	7.21	6.98	5.07	5.89
Royalties Paid	0.68	0.26	0.19	0.53
Production and Transportation Costs	1.42	1.37	1.27	1.90
Netback[(1)]	5.11	5.35	3.61	3.46

Note:

(1) Netback is calculated by deducting royalties paid and production costs from prices received.

Production Volume by Field

The following table indicates the average daily production from each of the Corporation's core properties for the year ended December 31, 2007:

Field	Natural Gas (Mcf/d)	BOE (BOE/d)	%
Fenn Big Valley	5,255	876	90.2
Acme	356	59	6.1
Rosalind	71	12	1.2
Manola	147	24	2.5
Total	5,829	971	100.0

DIRECTORS AND OFFICERS OF EMBER

Directors and Officers

The name, municipality of residence, principal occupation for the prior five years and position with Ember, of each of the directors and officers of Ember are as follows:

Name and Residence	Position with Ember	Principal Occupation During Previous Five Years
Douglas A. Dafoe Calgary, Alberta	Chairman, Chief Executive Officer and Director	From July 2005 to present, Chairman and Chief Executive Officer of Ember. Prior thereto, from October 1995 to July 2005, President and Chief Executive Officer of Thunder.
Terence S. Meek Calgary, Alberta	President and Chief Operating Officer and Director	From July 2005 to present, President and Chief Operating Officer of Ember. Prior thereto, from July 1995 to June 2005, Vice President, Engineering and Chief Operating Officer of Thunder.
J.W. (Jack) Peltier(1)(2)(4) Calgary, Alberta	Lead Director	From 1978 to present, President of Ipperwash Resources Ltd., a company engaged in oil and gas investments and consulting services.
Colin D. Boyer(2)(4) Calgary, Alberta	Director	From August 2006 to present, Independent Businessman. Prior thereto, from March 2004 to August 2006, President of Birchill Energy Limited, an oil and gas company. From May 2000 to March 2004, President of Birchill Resources Ltd., an oil and gas company.
Richard A.M. Todd(3) Calgary, Alberta	Director	From December 2006 to present, Chairman and Chief Executive Officer of OSUM Oil Sands Corp. Prior thereto, from January 2002 to July 2005, President and Chief Executive Officer of Mustang. From July 1990 to April 1999, President and Chief Executive Officer of Richland Petroleum Corporation.
F. Fox Benton III(1)(3) Houston, Texas	Director	Independent Businessman. Prior thereto, from June 1999 to February 2005, Chief Financial Officer of Ultra Petroleum Corp.
Thomas S. Drolet(3) Englewood, Florida	Director	From January 2001 to December 2005, Vice-President, International Business of DTE Energy Technologies Inc.

Name and Residence	Position with Ember	Principal Occupation During Previous Five Years
Dennis B. Balderston(1) Calgary, Alberta	Director	From July 2005 to present, Independent Businessman. Prior thereto, from September 1990 to June 2005, a Partner with Ernst & Young LLP, a firm of Chartered Accountants
Jeff van Steenbergen(2)(4) Calgary, Alberta	Director	From June 2001 to present, General Partner of KERN Partners Ltd., a private equity firm.
Bruce C. Ryan Calgary, Alberta	Vice President, Finance and Chief Financial Officer	From September 2005 to present, Vice President, Finance and Chief Financial Officer of Ember. Prior thereto, from September 2004 to September 2005, Vice President, Finance and Chief Financial Officer of Drilcorp Energy Ltd., an oil and gas company. From June 2002 to December 2003, Vice President, Finance and Chief Financial Officer of Mind's Eye Entertainment, a film production company.
Thomas A. Zuorro Calgary, Alberta	Vice President, Land	From October 2005 to present, Vice President, Land of Ember since. Prior thereto, from December 2004 to October 2005, Vice President, Land of Thunder. From May 2004 to December 2004, Land Manager of Thunder. From August 2001 to May 2004, Vice President, Land & Contracts of Grey Wolf Exploration Inc., an oil and gas company.
Kenneth S. Ronaghan Calgary, Alberta	Vice President, Engineering	From November 2005 to present, Vice President, Engineering of Ember. Prior thereto, from September 2001 to October 2005, Exploitation Manager of Thunder. From January 1998 to April 2001, Exploitation Manager of Cypress Energy Inc.
Steven R. Gell Calgary, Alberta	Vice President, Production	From July 2007 to present, Vice President, Production of Ember. Prior thereto, from July 2005 to June 2007, Vice President, Production of Thunder. From December 2004 to July 2005, Vice President, Production. From July 1997 to December 2004, Manager, Production of Thunder.
Kent D. Kufeldt Calgary, Alberta	Corporate Secretary	Partner of the law firm of Macleod Dixon LLP.

Notes:
(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Corporate Governance, Board Nomination and Compensation Committee.
(4) Member of the Health, Safety and Environment Committee.

Messrs. Dafoe, Meek, Peltier, Boyer and Todd have been directors of Ember since June 2005. Messrs. Benton, Drolet and Balderston have been directors since July 2005. Mr. van Steenbergen was appointed a director in March 2007. Each of the directors has been elected or appointed to serve as such until the next annual meeting of the shareholders of Ember or until his successor is duly elected or appointed, unless his office is earlier vacated in accordance with Ember's articles or by-laws.

As at March 7, 2008, the directors and senior officers of Ember as a group beneficially owned, directly or indirectly, or exercised control or direction over 3,200,011 Common Shares of Ember representing 8.86% of the 36,103,326 outstanding Common Shares. In addition, Mr. van Steenbergen is a manager of KERN Energy Partners II, L.P. and KERN Energy Partners II U.S., L.P., the beneficial holders of 7,214,882

Common Shares representing 19.98% of the outstanding Common Shares which when combined with the holdings above totals 10,414,893 Common Shares and represents 28.84% of the outstanding Common Shares.

Corporate Cease Trade Orders or Bankruptcies

In the 10 years preceding the date of this Annual Information Form, none of the directors, officers or insiders of the Corporation are or have been a director or officer of any other issuer that, while acting in such capacity, was subject to any corporate cease trade order or bankruptcies.

Penalties or Sanctions

None of the directors, officers or insiders of the Corporation have been subject to any penalties or sanctions under securities legislation.

Personal Bankruptcies

To the knowledge of management of Ember, there has been no director or officer, or any shareholder holding a sufficient number of securities of Ember to affect materially the control of Ember that is, or within the 10 years before the date of this Annual Information Form has been, a director or officer of any other issuer that, while that person was acting in that capacity:

(a) was the subject of a cease trade or similar order, or an order that denied the other issuer access to any exemptions under Canadian securities legislation, for a period of more than 30 consecutive days; or

(b) became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

To the knowledge of management of the Ember, there has been no director or officer, or any shareholder holding sufficient number of securities of Ember to affect materially the control of Ember, or a personal holding company of any such person that has, within the 10 years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or was subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director or officer.

To the knowledge of management of Ember, no director or officer, or any shareholder holding a sufficient number of securities of Ember to affect materially the control of Ember, has:

(a) been subject to any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with the Canadian securities regulatory authority; or

(b) been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

EMBER SHARE CAPITAL

Common Shares

Ember is authorized to issue an unlimited number of Common Shares. Holders of Common Shares are entitled to one vote per share at meetings of shareholders of Ember, to receive dividends if, as and when declared by the board of directors and to receive pro rata the remaining property and assets of Ember upon its dissolution or winding-up, subject to the rights of shares having priority over the Common Shares.

Ember Non-Voting Shares

Ember is authorized to issue an unlimited number of Ember non-voting shares (the "Ember Non-Voting Shares"). Holders of Ember Non-Voting Shares are entitled to receive dividends if, as and when declared by the board of directors and to receive pro rata the remaining property and assets of Ember upon its dissolution or winding-up, subject to the rights of shares having priority over the Ember Non-Voting Shares. Holders of Ember Non-Voting Shares are not entitled to vote at meetings of shareholders of Ember except as required under the ABCA. Pursuant to the Arrangement, each Ember Non-Voting Share that was outstanding was exchanged for one Ember Share and was cancelled pursuant to a reorganization of the capital of Ember.

Ember Performance Shares

Ember is authorized to issue up to 1,400,000 Ember Performance Shares without nominal or par value. The Ember Performance Shares rank junior to the Common Shares and Ember Non-Voting Shares, other than as set forth below. Holders of Ember Performance Shares will not be entitled to vote at meetings of shareholders of Ember except as required under the ABCA and will not be entitled to receive dividends. The Ember Performance Shares will not be entitled to receive any property or assets of Ember upon its dissolution or winding-up other than an amount of $0.01 per share in preference over the Common Shares.

1,400,000 Ember Performance Shares have been issued to certain employees, contractors, officers and directors of Ember (the "Ember Service Providers"). Each Ember Performance Share was purchased by the holder at a price of $0.01 per share and will be convertible into the fraction of an Ember share equal to the closing trading price of the Common Shares on the TSX or such other stock exchange on which the Common Shares are listed on the trading day prior to such conversion (the "Ember Closing Price") less $1.93, divided by the Ember Closing Price. The Ember Performance Shares will vest and become convertible as to one-third on each of the first, second and third anniversaries from the date of grant (July 6, 2005) if the holder is an Ember Service Provider on such date.

Upon a holder ceasing to be a Ember Service Provider, Ember will, subject to applicable law, redeem the Ember Performance Shares at a redemption price of $0.01 per share. In the event that Ember is unable to pay the redemption price in accordance with applicable law, the Ember Performance Shares which were to be redeemed will be cancelled and the former holders will only have the right to receive $0.01 per share.

The Ember Performance Shares will operate in concert with Ember's stock option plan and the number of Common Shares reserved for issuance under the stock option plan and the Ember Performance Shares shall not exceed 10% of the outstanding Common Shares at any time.

Shareholder Rights Plan

On October 18, 2006 the Corporation held a Special Meeting of shareholders at which the shareholders ratified and approved the Shareholder Rights Plan (the "Plan") of Ember which was adopted pursuant to a Shareholder Rights Agreement (the "Agreement") dated August 9, 2006 between Ember and Olympia Trust Company, as rights agent (the "Rights Agent").

The Board of Directors adopted the Plan to ensure, to the extent possible, that all shareholders of Ember are treated equally and fairly in connection with any takeover bid or similar offer for all or a portion of the outstanding Common Shares.

Purpose of the Plan

The objectives of the Plan are to ensure, to the extent possible, that all shareholders of Ember are treated equally and fairly in connection with any takeover bid for Ember. Takeover bids may be structured to be coercive or may be initiated at a time when the Board of Directors will have a difficult time preparing an adequate response to the offer. Accordingly, such offers do not always result in shareholders receiving equal or fair treatment or full or maximum value for their investment. Under current Canadian securities legislation, a takeover bid is required to remain open for 35 days, a period of time which the Board of Directors believes is insufficient for the directors to: (i) evaluate a takeover bid (particularly if it includes consideration other than cash); (ii) explore, develop and pursue alternatives which are superior to the takeover bid and which could maximize shareholder value; and (iii) make reasoned recommendations to the shareholders.

The Plan discourages discriminatory, coercive or unfair takeovers of Ember and gives the Board of Directors time if, in the circumstances, the Board of Directors determines it is appropriate to take such time, to pursue alternatives to maximize shareholder value in the event an unsolicited takeover bid is made for all or a portion of the outstanding Common Shares of Ember. As set forth in detail below, the Plan discourages coercive hostile takeover bids by creating the potential that any Common Shares which may be acquired or held by such a bidder will be significantly diluted. The potential for significant dilution to the holdings of such a bidder can occur as the Plan provides that all holders of Common Shares who are not related to the bidder will be entitled to exercise rights issued to them under the Plan and to acquire Common Shares at a substantial discount to prevailing market prices. The bidder or the persons related to the bidder will not be entitled to exercise any Rights under the Plan. Accordingly, the Plan will encourage potential bidders to make takeover bids by means of a Permitted Bid (as defined below) or to approach the Board of Directors to negotiate a mutually acceptable transaction. The Permitted Bid provisions of the Plan are designed to ensure that in any takeover bid for outstanding Common Shares of Ember all shareholders are treated equally and are given adequate time to properly assess such takeover bid on a fully-informed basis.

The Plan was not being proposed in response to, or in anticipation of, any pending, threatened or proposed acquisition or takeover bid.

The Board of Directors did not adopt the Plan to prevent a takeover of Ember, to secure the continuance of management or the directors in their respective offices or to deter fair offers for the Common Shares.

Summary of the Plan

The following summary of terms of the Plan is qualified in its entirety by reference to the text of the Agreement. A shareholder or other interested party may obtain a copy of the Agreement, which is available on SEDAR at www.sedar.com or, by contacting the Vice President Finance and Chief Financial Officer of Ember.

Term

The Plan (unless earlier terminated) will remain in effect until termination of the annual meeting of shareholders of Ember in 2009 unless the term of the Agreement is extended beyond such date by resolution of shareholders at a shareholders' meeting.

Issue of Rights

One right (a "Right") has been issued by Ember pursuant to the Agreement in respect of each Common Share of Ember outstanding at the close of business on August 9, 2006 (the "Record Time"). One Right will also be issued for each additional Common Share issued after the Record Time and prior to the earlier of the Separation Time (as defined below) or the Expiration Time (as defined below).

Rights Exercise Privilege

The Rights will separate from the voting shares to which they are attached and become exercisable at the time (the "Separation Time") which is 10 trading days following the date a person becomes an Acquiring Person or announces an intention to make a takeover bid that is not an acquisition pursuant to a takeover bid permitted by the Plan (a "Permitted Bid").

Any transaction or event in which a person (an "Acquiring Person"), including associates and affiliates and others acting in concert, acquires (other than pursuant to an exemption available under the Plan or a Permitted Bid) Beneficial Ownership (as defined in the Plan) of 20% or more of the voting shares of Ember is referred to as a "Flip-in Event". Any Rights held by an Acquiring Person on or after the earlier of the Separation Time or the first date of public announcement by Ember or an Acquiring Person that an Acquiring Person has become such, will become void and the Rights (other than those held by the Acquiring Person) will permit the holder to purchase Common Shares at a substantial discount to their then prevailing market price.

The issuance of the Rights is not dilutive and will not affect reported earnings or cash flow per share until the Rights separate from the underlying Common Shares and become exercisable or until the exercise of the Rights. The issuance of the Rights will not change the manner in which shareholders currently trade their Common Shares.

Permitted Lock-Up Agreement

A person will not become an Acquiring Person by virtue of having entered into an agreement (a "Permitted Lock-Up Agreement") with a shareholder whereby the shareholder agrees to deposit or tender voting shares to a takeover bid made by such person, provided that the agreement meets certain requirements including:

(a) the terms of the agreement are publicly disclosed and a copy of the agreement is publicly available;

(b) the shareholder who has agreed to tender voting shares to the takeover bid (the "Lock-Up Bid") made by the other party to the agreement is permitted to terminate its obligation under the agreement in order to tender voting shares to another takeover bid or transaction where: (i) the offer price or value of the consideration payable under the other takeover bid or transaction is greater than the price or value of the consideration per share at which the shareholder has agreed to deposit or tender voting shares to the Lock-Up Bid or is equal to or greater than a specified minimum which is not more than 7% higher than the offer price under the Lock-Up Bid; and (ii) if the number of voting shares offered to be purchased under the Lock-Up Bid is less than all of the voting shares held by shareholders (excluding shares held by the offeror), the number of voting shares offered to be purchased under the other takeover bid or transaction (at an offer price not lower than in the Lock-Up Bid) is greater than the number of voting shares offered to be purchased under the Lock-Up Bid or is equal to or greater than a specified number which is not more than 7% higher than the number of voting shares offered to be purchased under the Lock-Up Bid; and

(c) no break-up fees or other penalties that exceed in the aggregate the greater of 2.5% of the price or value of the consideration payable under the Lock-Up Bid and 50% of the increase in consideration resulting from another takeover bid or transaction shall be payable by the shareholder if the shareholder fails to deposit or tender voting shares to the Lock-Up Bid.

Certificates and Transferability

Prior to the Separation Time, the Rights will be evidenced by a legend imprinted on certificates for Common Shares issued from and after the effective date (the "Effective Date") of the Agreement (being the later of the date of the Agreement and the receipt by Ember of all regulatory approvals with respect to the Agreement). Rights are also attached to Common Shares outstanding on the Effective Date, although share certificates issued prior to the Effective Date will not bear such a legend. Shareholders are not required to return their certificates in order to have the benefit of the Rights. Prior to the Separation Time, Rights will trade together with the Common Shares and will not be exercisable or transferable separately from the Common Shares. From and after the Separation Time, the Rights will become exercisable, will be evidenced by Rights Certificates and will be transferable separately from the Common Shares.

Permitted Bid Requirements

The requirements of a "Permitted Bid" include the following:

(a) the takeover bid must be made by means of a takeover bid circular;

(b) the takeover bid is made to all holders of voting shares as registered on the books of Ember, other than the offeror;

(c) the takeover bid contains, and the take-up and payment for securities tendered or deposited is subject to, an irrevocable and unqualified provision that no voting shares will be taken up or paid for pursuant to the takeover bid prior to the close of business on the date which is not less than 60 days following the date of the takeover bid and only if at such date more than 50% of the voting shares held by independent shareholders shall have been deposited or tendered pursuant to the takeover bid and not withdrawn;

(d) the takeover bid contains an irrevocable and unqualified provision that unless the takeover bid is withdrawn, voting shares may be deposited pursuant to such takeover bid at any time during the period of time between the date of the takeover bid and the date on which voting shares may be taken up and paid for and that any voting shares deposited pursuant to the takeover bid may be withdrawn until taken up and paid for; and

(e) the takeover bid contains an irrevocable and unqualified provision that if, on the date on which voting shares may be taken up and paid for, more than 50% of the voting shares held by independent shareholders shall have been deposited pursuant to the takeover bid and not withdrawn, the offeror will make a public announcement of that fact and the takeover bid will remain open for deposits and tenders of voting shares for not less than ten business days from the date of such public announcement.

The Plan allows for a competing Permitted Bid (a "Competing Permitted Bid") to be made while a Permitted Bid is in existence. A Competing Permitted Bid must satisfy all of the requirements of a Permitted Bid except that it may expire on the same date as the Permitted Bid, subject to the requirement that it be outstanding for a minimum period of 35 days.

Waiver and Redemption

If a potential offeror does not desire to make a Permitted Bid, it can negotiate with, and obtain the prior approval of, the Board of Directors to make a takeover bid by way of a takeover bid circular sent to all holders of voting shares on terms which the Board of Directors considers fair to all shareholders. In such circumstances, the Board of Directors may waive the application of the Plan thereby allowing such bid to proceed without dilution to the offeror. Any waiver of the application of the Plan in respect of a particular takeover bid shall also constitute a waiver of any other takeover bid which is made by means of a takeover bid circular to all holders of voting shares while the initial takeover bid is outstanding. The Board of Directors may also waive the application of the Plan in respect of a particular Flip-in Event that has occurred through inadvertence, provided that the Acquiring Person that inadvertently triggered such Flip-in Event reduces its beneficial holdings to less than 20% of the outstanding voting shares of Ember within 14 days or such earlier or later date as may be specified by the Board. With the prior consent of the holders of voting shares, the Board of Directors may, prior to the occurrence of a Flip-in Event that would occur by reason of an acquisition of voting shares otherwise than pursuant to the foregoing, waive the application of the Plan to such Flip-in Event.

The Board of Directors may, with the prior consent of the holders of voting shares, at any time prior to the occurrence of a Flip-in Event, elect to redeem all but not less than all of the then outstanding Rights at a redemption price of $0.00001 per Right. Rights are deemed to be redeemed following completion of a Permitted Bid, a Competing Permitted Bid or a takeover bid in respect of which the Board of Directors has waived the application of the Plan.

Exemptions for Investment Advisors

Investment advisors (for client accounts), trust companies (acting in their capacity as trustees or administrators), statutory bodies whose business includes the management of funds (for employee benefit plans, pension plans, or insurance plans of various public bodies) and administrators or trustees of registered pension plans or funds acquiring greater than 20% of the voting shares are exempted from triggering a Flip-in Event, provided they are not making, either alone or jointly or in concert with any other person, a takeover bid.

Board of Directors

The adoption of the Plan will not in any way lessen or affect the duty of the Board of Directors to act honestly and in good faith with a view to the best interests of Ember. The Board of Directors, when a takeover bid or similar offer is made, will continue to have the duty and power to take such actions and make such recommendations to shareholders as are considered appropriate.

Amendment

Ember may, with the prior approval of shareholders (or the holders of Rights if the Separation Time has occurred), supplement amend, vary or delete any of the provisions of the Agreement. Ember may make amendments to the Agreement at any time to correct any clerical or typographical error or, subject to confirmation at the next meeting of shareholders, make amendments which are required to maintain the validity of the Agreement due to changes in any applicable legislation, regulations or rules.

DIVIDEND POLICY

Ember has not declared or paid any dividends on the Common Shares since its incorporation. Any decision to pay dividends on the Common Shares will be made by the board of directors of Ember on the basis of Ember's earnings, financial requirements and other conditions existing at such future time.

PRIOR SALES

On June 3, 2005, Ember issued one Common Share at a price of $1.00 to facilitate its organization.

In connection with the Arrangement, Ember issued 20,323,130 Common Shares to acquire certain natural gas rights associated with coal from Thunder.

On July 6, 2005, Ember issued 3,108,888 Ember Non-Voting Shares at a price of $1.93 per Ember Non-Voting Share and 1,400,000 Ember Performance Shares at a price of $0.01 per Ember Performance Share for aggregate gross proceeds of $6,014,859.

On August 31, 2005, Ember completed a bought deal financing of 7,000,000 Common Shares at a price of $7.15 per share for gross proceeds of $50,050,000.

Concurrent with the completion of the Acme Acquisition on March 1, 2007, Ember completed a private placement to a Calgary based private equity firm of 5,660,400 Common Shares at a purchase price of $2.65 per share. Total proceeds of $15 million were used to complete the Acme Acquisition, with the balance of $6.25 million to be used to expand Ember's capital program for 2007.

MARKET FOR COMMON SHARES

The Common Shares of Ember are listed and posted for trading on the TSX under the symbol "EBR". The following table sets forth the reported market price ranges and the trading volumes for the Common Shares for the periods indicated, as reported by the TSX.

	Price Range ($)		
Period	High	Low	Trading Volume
January 2007	2.80	2.38	1,042,515
February 2007	2.99	2.45	690,765
March 2007	2.98	2.35	1,284,697
April 2007	2.75	2.41	827,279
May 2007	2.78	2.00	1,573,195
June 2007	2.73	2.27	2,384,087
July 2007	2.60	2.33	1,206,980
August 2007	2.50	1.69	1,135,971
September 2007	1.94	1.58	512,542
October 2007	1.85	1.41	1,132,982
November 2007	1.75	1.10	5,240,015
December 2007	1.36	1.03	3,474,555
January 2008	1.40	1.15	1,481,170

	Price Range ($)		
Period	High	Low	Trading Volume
February 2008	1.90	1.30	619,366
March 1 to 18, 2008	1.70	1.40	44,846

AUDIT COMMITTEE

Composition of the Audit Committee and Charter

The Audit Committee of the Board of Directors of the Corporation operates under a written charter that sets out its responsibilities and composition requirements. A copy of the charter is attached to this AIF as Appendix "C". The Audit Committee consists of Dennis Balderston (Chairman), F. Fox Benton III and J.W. Peltier. All members of the Audit Committee are independent and financially literate (as determined by Multilateral Instrument 52-110, *Audit Committees*). In considering criteria for the determination of financial literacy, the Board of Directors of the Corporation looks at the ability to read and understand financial statements of a publicly traded corporation. The following sets out the education and experience of each director relevant to the performance of his duties as a member of the Audit Committee.

Mr. Balderston is a Chartered Accountant and a retired partner with Ernst & Young LLP, a firm of Chartered Accountants, and his expertise is particularly important in his capacity as Chairman of the Audit Committee. Mr. Balderston holds a Bachelor of Commerce degree and a Chartered Accountant designation.

Mr. Peltier has been President of Ipperwash Resources Ltd., a company engaged in oil and gas exploration and production, investments, consulting and management services and portfolio investments. Mr. Peltier holds a Bachelor of Science degree, a Masters in Business Administration degree and a Chartered Financial Analyst designation.

Mr. Benton was the Chief Financial Officer of Ultra Petroleum Corp. and has over 16 years experience in the oil and gas industry. Mr. Benton holds a Bachelor of Arts degree and a Masters in Business Administration degree.

Auditors' Fees

Ernst & Young LLP has served as Ember's auditors since incorporation. Fees paid to Ernst & Young LLP for the year ended December 31, 2007 are detailed below:

	For the year ended December 31, 2007	**For the year ended December 31, 2006**
Audit	$55,000	$57,000
Audit related	$44,000	45,000
Tax	$73,500	9,000
Other	$19,000	7,000
Total	$191,500	$118,000

Audit fees were paid for professional services rendered by the auditors for the audit of the Corporation's annual financial statements and the review of interim financial statements. Audit related fees pertain to services rendered in connection with a private placement. All permissible categories of non-audit services to be provided by the external auditor must be pre-approved by the Audit Committee subject to certain statutory exceptions.

CONFLICTS OF INTEREST

Circumstances may arise where members of the board of directors of Ember are directors or officers of corporations which are in competition to the interests of Ember. No assurances can be given that opportunities identified by such board members will be provided to Ember. Pursuant to the ABCA, directors who have an interest in a proposed transaction upon which the board of directors is voting are required to disclose their interests and refrain from voting on the transaction.

RISK FACTORS

An investment in Ember should be considered speculative due to the nature of Ember's activities and the present stage of its development. Investors should carefully consider the following risk factors:

Industry and Environmental Matters

The petroleum industry is competitive in all its phases. Ember will compete with numerous other participants in the search for and the acquisition of natural gas properties and in the marketing of natural gas. Its competitors will include companies which have greater financial resources, staff and facilities than those of Ember. Ember's ability to increase reserves in the future will depend not only on its ability to develop its present properties, but also on its ability to select and acquire suitable producing properties or prospects for exploratory drilling.

The marketability of natural gas acquired or discovered will be affected by numerous factors beyond the control of Ember. These factors include reservoir characteristics, market fluctuations, the proximity and capacity of natural gas pipelines and processing equipment and government regulation. 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. Ember's natural gas operations may also be subject to compliance with federal, provincial and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment.

Coal Bed Methane Operations

CBM operations in Western Canada are in the early stages of development. As a result, many factors affecting the economics and success of CBM operations are unknown or not fully known at this time.

Ember has a number of demonstration projects that have been designed to provide the Corporation with information regarding well productivity, reserve recovery factors and reservoir characteristics. This information is required to advance the project areas to commercial development.

Ember's business is subject to all of the operating risks associated with drilling for and producing natural gas, including fires, explosions, blow-outs and surface cratering, uncontrollable flows of underground natural gas, formation water, natural disasters, pipe or cement failures, casing collapses, embedded oilfield drilling and service tools, abnormally pressured formations and environmental hazards, such as natural gas leaks, pipeline ruptures and discharges of toxic gases.

In addition, the exploration for, and production of CBM, differs from conventional oil and gas and can pose additional operating risks.

CBM can require higher capital commitments than similar depth conventional gas developments due to such factors as the type of drilling and completion techniques required, which can entail the complexity of development of multiple coal steams. In some instances, more wells per section are required to effectively develop the resource in place. Lower wellhead pressures are typical with CBM production which can require additional compression or larger flow lines.

CBM also requires a longer timeframe for testing and development. Coalbed methane often comes with water. In a sandstone or limestone reservoir, the gas molecules are between the rock particles. With CBM, the gas molecules are stuck to the coal or adsorbed, and the spaces between the coal, referred to as the "cleats", must be drained of water before gas will come out of the coal. The length of this dewatering process is different in each instance, and in some instances can be lengthy before CBM production begins. Ember's operations may require long lead times before peak production is reached, and the sustainability of production is subject to greater uncertainty than with conventional gas.

Water production from CBM firstly requires adequate disposal into government approved formations. The large volumes produced potentially create such operational concerns as freezing, scale formation, or backpressure caused by inefficient pumping.

As CBM is relatively new in Canada, there is additional regulatory complexity. This includes uncertainty or limitations to development from outstanding CBM ownership questions regarding freehold lands. With the recent introduction of CBM development in Canada, operators drilling or producing CBM wells are subject to public scrutiny. Any problems experienced by other operators might adversely impact Ember, through additional regulations or greater difficulty in acquiring leases, permits or regulatory approvals.

In addition, Ember could incur substantial losses as a result of loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties, suspension of the Corporation's operations and repairs to resume operations.

Long Lead Production Times

CBM often comes with water. In a sandstone or limestone reservoir, the gas molecules are between the rock particles. In coalbed, the gas molecules are stuck to the coal or adsorbed, and the spaces between the coal, referred to as the "cleats", must be drained of water before gas will come out of the coal. The length of this dewatering process is different in each instance and in some cases can be lengthy before coalbed methane production begins. Ember may have to put up with long lead times before seeing any cash flow from a well.

Volatility of Gas Prices and Markets

Natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of Ember's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of Ember's reserves. Ember might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Ember's net production revenue causing a reduction in its acquisition and development activities. In addition, bank borrowings available to Ember will in part be determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could further reduce such borrowing base, therefore reducing the bank credit available and could require that a portion of its bank debt be repaid.

From time to time Ember may enter into agreements to receive fixed prices on its 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, Ember will not benefit from such increases.

Price Volatility of Publicly Traded Securities

In recent years, the securities markets in Canada and the United States have experienced a high level of price and volume volatility, and the market price of securities of many companies, particularly those considered to be development stage companies, have experienced wide fluctuations in price which have not necessarily been related to the operating performance, underlying asset values or prospects of such companies. There can be no assurance that continual fluctuations in price will not occur. It is likely that the market price for the Common Shares will be subject to market trends generally, notwithstanding the financial and operational performance of the respective companies.

Operational Risks

Natural gas exploration operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts and cratering, each of which could result in substantial damage to wells, producing facilities, other property and the environment or in personal injury. In accordance with industry practice, Ember will not be fully insured against all of these risks, nor are all such risks insurable. Although Ember will maintain liability insurance in an amount which it considers adequate, the nature of these risks is such that liabilities could exceed policy limits, in which event Ember could incur significant costs that could have a materially adverse effect upon its financial condition. Natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Natural gas exploration and development activities are dependent on the availability of drilling and related equipment 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 Ember and may delay exploration and development activities. To the extent Ember is not the operator of its 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. In addition, the success of Ember will be largely dependent upon the performance of its management and key employees. Ember does not have any key man insurance policies and, therefore, there is a risk that the death or departure of any member of management or any key employee could have a material adverse affect on the Corporation.

Technology Risk

Ember will rely on information technology to manage its day to day operations and perform reporting obligations including the preparation of financial statements, reporting to joint partners, and various governments in relation to payment of royalties and taxes.

Permits and Licenses

The operations of Ember may require licenses and permits from various governmental authorities. There can be no assurance that Ember will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at its projects.

Foreign Currency Exposure

From time to time Ember 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 or the risk of increased repayments on United States dollar denominated debt if the Canadian dollar declines in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, it will not benefit from the fluctuating exchange rate.

Title to Properties

Although title reviews will be done according to industry standards prior to the purchase of most natural gas producing properties or the commencement of drilling wells as determined appropriate by management, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat a claim of Ember which could result in a reduction of the revenue received by the Corporation.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived therefrom, including many factors beyond the control of Ember. The reserve and cash flow information set forth herein represent estimates only. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions and subject to change and are beyond the control of Ember. Actual production and cash flows derived therefrom will vary from these evaluations, and such variations could be material. These evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations.

Reserve Replacement

Ember's future natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves Ember may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in reserves will depend not only on Ember's ability to develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. There can be no assurance that Ember's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of natural gas.

Substantial Capital Requirements

Ember may have to make substantial capital expenditures for the acquisition, exploration, development and production of natural gas reserves in the future. If revenues or reserves decline, Ember may have limited ability to expend 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. Moreover, future activities may require Ember to alter its capitalization significantly. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on its financial condition, results of operations or prospects.

Issuance of Debt

From time to time Ember may enter into transactions to acquire assets or shares of other corporations. These transactions may be financed partially or wholly through debt, which may increase debt levels above industry standards. Ember may also incur debt for general corporate purposes. Ember's articles and by-laws do not limit the amount of indebtedness it may incur. The level of Ember's indebtedness from time to time could impair its ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise.

Environmental Regulation

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 nation-wide emissions of carbon dioxide, methane, nitrous oxide and other greenhouse gases, or GHGs. On October 19, 2006, the Canadian Federal Government introduced into Parliament the *Clean Air Act* (Bill C-30) and released its accompanying Notice of Intent to Develop and Implement Regulations and Other Measures to Reduce Air Emissions, or the "Notice". The Bill and the Notice were intended to reflect the Government's "made in Canada" approach to Canada's Kyoto Protocol obligations and reduce criteria air pollutants and GHG emissions in Canada. Bill C-30 had not received Royal Assent as of the proroguing of Parliament on September 14, 2007 and therefore died as of that date. However, the Government has continued to develop a framework for the regulation of GHGs. On April 26, 2007, the Government announced a Regulatory Framework for Air Emissions and Other Measures to Reduce Air Emissions, or the "Framework". The Framework proposed new requirements governing the emission of GHG's and other industrial air pollutants. On March 10, 2008, the Government further elaborated on the regulatory framework in *Turning the Corner: Taking Action to Fight Climate Change. Turning the Corner* sets a target of a 20 percent reduction in GHG emissions from 2006 levels by 2020 and a 60 to 70 percent reduction from 2006 levels by 2050. The reductions will be achieved by regulating specified industrial sectors including the oil and gas sector. The upstream oil and gas sector will be required to reduce GHG emissions intensity by 18 percent from 2006 levels by 2010 and by an additional 2 percent annually after 2010. The regulatory reduction obligations may be met through actual reductions in GHG emissions, contributions to a technology fund, domestic offsets, credits under the Kyoto Clean Development Mechanism and voluntary GHG reductions achieved between 1992 and 2006. The Government intends to publish draft regulations in the fall of 2008 and to publish final regulations by the fall of 2009 for implementation on January 1, 2010.

On April 20, 2007, the Government of Alberta passed the *Climate Change and Emissions Management Amendment Act* establishing a framework for GHG emission reductions. The *Specified Gas Emitters Regulation* created under the *Act* came into effect on July 1, 2007. The *Regulation* requires facilities that emit more than 100,000 tonnes of carbon dioxide equivalent annually to reduce their emission intensity for the July 1, 2007 to December 31, 2007 period by 12 percent from 2003-2005 levels. These obligations may be met through actual reductions in GHG emissions, the purchase of emission reduction or offset credits, or contributions to a provincial technology fund. On January 24, 2008, the Government of Alberta released its 2008 Climate Change Strategy. The goal of the strategy is to reduce GHG emissions in Alberta by 50 percent or 200 megatonnes below business as usual levels by 2050. Reductions in GHG emissions from energy production will account for 37 megatonnes or 18 percent of the proposed reductions. The Government proposes to use funds from the provincial technology fund to support the testing, demonstration and implementation of new technologies to reduce GHG emissions from energy production.

Future legislated GHG and industrial air pollutant emission reduction targets and emission intensity targets, or emission reduction requirements in future regulatory approvals, may require the reduction of emissions or emissions intensity from Ember's operations and facilities. The reductions may not be technically or economically feasible for Ember and the failure to meet such emission reduction requirements may materially adversely affect the Ember's business and result in fines, penalties and the suspension of operations. As well, equipment from suppliers which can meet future emission standards may not be available on an economic basis and other methods of reducing emissions or emission intensity to required levels in the future may significantly increase operating costs or reduce output. There is a risk that the federal and/or provincial governments could pass legislation which would tax such emissions or require, directly or indirectly, reductions in such emissions or emission intensity produced by energy industry participants for which Ember may be unable to mitigate. Mitigation of the risk of future legislative or regulatory limits on the emission of GHGs may include the acquisition of emission reduction or off-set credits from third parties. However, emission reduction or off set-credits may not be available for acquisition by Ember or may not be available on an economic basis and may not be recognized or qualify under future legislative or regulatory regimes as mitigation for the emission of GHGs by Ember.

Abandonment and Reclamation Costs

Ember will be responsible for compliance with terms and conditions of environmental and regulatory approvals and all laws and regulations regarding abandonment and reclamation in respect of its properties, which abandonment and reclamation costs may be substantial. A breach of such legislation or regulations may result in the imposition of fines and penalties, including an order for cessation of operations at the site until satisfactory remedies are made.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to resources and various properties in western Canada. Such claims, in relation to any of Ember's lands, if successful, could have an adverse effect on its operations.

Corporate Matters

To date, Ember has not paid any dividends on its outstanding Common Shares. Certain of the directors and officers of Ember are also directors and officers of other oil and gas companies involved in natural resource exploration and development, and conflicts of interest may arise between their duties as officers and directors of Ember, as the case may be, and as officers and directors of such other companies.

Possible Failure to Realize Anticipated Benefits of Acquisitions

Ember may complete acquisitions to strengthen its position in the natural gas industry and to create the opportunity to realize certain benefits including, among other things, potential cost savings. Achieving the benefits of any future acquisitions depends, in part, on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as Ember's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with its own. The integration of acquired businesses requires the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect Ember's ability to achieve the anticipated benefits of these and future acquisitions.

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 operations of Ember in a manner materially different than they would affect other oil and gas issuers of similar size. All current legislation is a matter of public record and Ember 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.

Canadian Government Regulation

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. It is not expected that any of these controls or regulations will affect the operations of Ember in a manner materially different than they would affect other oil and gas companies of similar size.

Pricing and Marketing - Oil, Natural Gas and Associated Products

In the provinces of Alberta, British Columbia and Saskatchewan oil, natural gas and associated products are generally sold at market index based prices. These indices are generated at various sales points depending on the commodity and are reflective of the current value of the commodity adjusted for quality and locational differentials. While these indices tend to track industry reference prices (ie. price of West Texas Intermediate crude oil at Cushing, Oklahoma or price of natural gas at Henry Hub, Louisiana), some variances can occur due to specific supply-demand imbalances. These differentials can change on a monthly or daily basis depending on the supply-demand fundamental at each location as well as other non-related changes such as the value of the Canadian dollar and the cost of transporting the commodity to the pricing point of the particular index.

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 and United States Free Trade Agreement. 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; or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

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

Provincial Royalties and Incentives

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 and the type or quality of the petroleum product produced.

From time to time 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.

Crude oil and natural gas royalty programs for specific wells and royalty reductions will reduce the amount of Crown royalties paid by Ember to the provincial governments.

Land Tenure

Crude oil and natural gas located in Western Canada is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses 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 on freehold lands are granted by lease on such terms and conditions as may be negotiated.

Environmental Regulation

The oil and natural gas industry is subject to environmental regulation pursuant to a variety of international conventions and Canadian federal, provincial and municipal laws, regulations, and guidelines. Such regulation provides for restrictions and prohibitions on the release or emissions of various substances produced in association with certain oil and gas industry operations. In addition, such regulation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such regulation 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.

The primary environmental legislation in Alberta is the *Environmental Protection and Enhancement Act* which regulates emissions and releases of substances, hazardous substances, remediation and reclamation of lands, waste management and environmental reporting. The diversion of non-saline water, including the dewatering of CBM wells, requires a licence and is regulated pursuant to the *Water Act*. CBM wells are also regulated under the *Oil and Gas Conservation Act*, regulations under that *Act* and directives of the Energy Resources Conservation Board, including requirements for baseline water well testing for CBM wells and requirements for reclamation and abandonment of wells.

Ember is 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 federal and Alberta environmental legislation and similar legislation in other jurisdictions in which it operates. Ember believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

Canada is a signatory to the United Nations Framework Convention on Climate Change. Canada has ratified the Kyoto Protocol established thereunder and the Kyoto Protocol has now come into effect. Annex B parties to the Kyoto Protocol, including Canada, are required to establish legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". Ember's exploration and production facilities and other operations and activities will emit a small amount of greenhouse gasses which may subject Ember to legislation in Canada regulating emissions of greenhouse gases. The Government of Canada has proposed legislation which would set greenhouse gas emissions reduction requirements for various industrial sectors, including oil and gas exploration and production. Future Canadian federal legislation, together with future provincial emission reduction requirements, may require the reduction of emissions or emissions intensity from Ember's operations and facilities. The direct and indirect costs of complying with these emissions regulations may adversely affect the business of Ember. See "Risk Factors - Environmental Regulation".

LEGAL PROCEEDINGS

There are currently no outstanding legal proceedings in which Ember is involved that are outside the ordinary course of business or that Ember would anticipate would result in a material adverse impact to Ember, its financial condition or its results of operations.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director, officer or principal shareholder of Ember, nor any affiliate or associate of such a person, has or has had any material interest in any transaction or any proposed transaction which materially affects Ember since its incorporation.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Corporation are Ernst & Young LLP, Chartered Accountants, Suite 1000, 440 – 2nd Avenue S.W., Calgary, Alberta, T2P 5E9.

The transfer agent and registrar for Common Shares is Olympia Trust Company at its office in Calgary, Alberta and of its agent in Toronto, Ontario.

MATERIAL CONTRACTS

The long term processing agreement between Ember and AltaGas as more particularly described under the heading "Statement of Reserves Data and Other Oil and Gas Information - Principal Properties" may be considered material to Ember.

INTERESTS OF EXPERTS

Reserve estimates contained in this Annual Information Form have been prepared by Sproule Associates Limited and McDaniel & Associates Consultants Ltd. As at December 31, 2007, the effective date of those estimates, and as at the date of this Annual Information Form, the principals, directors, officers and associates of Sproule Associates Limited and McDaniel & Associates Consultants Ltd., as a group, owned, directly or indirectly, less than 1% of the outstanding Common Shares.

The auditors of the Corporation, Ernst & Young LLP, are independent with respect to the Corporation, in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information, including information as to directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans, if applicable, is contained in the Proxy Statement and Information Circular of the Corporation prepared in connection with the most recent annual meeting of shareholders of the Corporation that involved the election of directors. Additional financial information is provided in the Corporation's financial statements and management discussion and analysis for the year ended December 31, 2007, which are contained in the Annual Report of the Corporation for the year ended December 31, 2007.

Copies of this Annual Information Form, the Corporation's Annual Report, any interim financial statements of the Corporation subsequent to those statements contained in the Annual Report, the Corporation's Proxy Statement and Information Circular and other additional information relating to the Corporation are available on SEDAR at www.sedar.com.

APPENDIX "A"

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

Terms to which a meaning is ascribed in National Instrument 51-101 have the same meaning herein.

To the board of directors of Ember Resources Inc. (the "Company"):

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

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

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

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

4. The following table sets forth the estimated future net revenue attributed to proved plus probable reserves, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10%, included in the reserves data of the Company evaluated by us as of December 31, 2007, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and board of directors.

			Net Present Value of Future Net Revenue (10% discount rate)			
Independent Qualified Reserves Evaluator or Auditor	**Description and Preparation Date of Evaluation Report**	**Location of Reserves (Country)**	**Audited (MM$)**	**Evaluated (MM$)**	**Reviewed (MM$)**	**Total (MM$)**
Sproule	Evaluation of the P&NG Reserves of Ember Resources, as of December 31, 2007, prepared November 2007 to February 2008	Canada	Nil	62,581	Nil	62,581
McDaniel	(as above)	Canada	Nil	34,622	Nil	34,621
Total			**Nil**	**97,202**	**Nil**	**97,202**

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.

6. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

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

Executed as to our report referred to above:

Sproule Associates Limited	*"original signed"*
Calgary, AB, Canada	R. Keith MacLeod, P. Eng.
February 28, 2008	President
McDaniel & Associates Consultants Ltd.	*"original signed"*
Calgary, AB, Canada	P. A. Welch, P. Eng.
February 28, 2008	President & Managing Director

APPENDIX "B"

REPORT ON RESERVES DATA BY MANAGEMENT

Terms to which a meaning is ascribed in National Instrument 51-101 have the same meaning herein.

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

Independent qualified reserves evaluators have evaluated and reviewed the Corporation's reserves data. The report of the independent qualified reserves evaluators is presented in Appendix "A" to the Annual Information Form of Ember Resources Inc. effective as at December 31, 2007.

The Reserves Committee of the Board of Directors of the Corporation has:

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

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

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

The Reserves Committee of the Board of Directors has reviewed the Corporation'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, on the recommendation of the Reserves Committee approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

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

"Douglas A. Dafoe"

Douglas A. Dafoe, Chairman and
Chief Executive Officer

"Terence S. Meek"

Terence S. Meek, President and
Chief Operating Officer

"Colin D. Boyer"

Colin D. Boyer, Director

"J.W. Peltier"

J.W. Peltier, Director

Dated March 20, 2008

APPENDIX "C"

AUDIT COMMITTEE CHARTER

EMBER RESOURCES INC.

Policy Statement

It is the policy of Ember Resources Inc. (the "Corporation") to establish and maintain an Audit Committee, composed entirely of independent directors, to assist the Board of Directors (the "Board") in carrying out their oversight responsibility for the Corporation's audit process (internal and external), internal controls, financial reporting and risk management processes. The Audit Committee will be provided with resources commensurate with the duties and responsibilities assigned to it by the Board including administrative support. If determined necessary by the Audit Committee, it will have the discretion to institute investigations of improprieties, or suspected improprieties within the scope of its responsibilities, including the standing authority to retain special counsel or experts.

Composition of the Committee

1. The Audit Committee shall consist of at least three directors. The Board shall appoint the members of the Audit Committee and may seek the advice and assistance of the Compensation Committee in identifying qualified candidates. The Board shall appoint one member of the Audit Committee to be the Chair of the Audit Committee.

2. Each director appointed to the Audit Committee by the Board must be independent. A director is independent if the director has no direct or indirect material relationship with the Corporation. A material relationship means a relationship which could, in the view of the Board, reasonably interfere with the exercise of the director's independent judgment. In determining whether a director is independent of management, the Board shall make reference to the then current legislation, rules, policies and instruments of applicable regulatory authorities.

3. Each member of the Audit Committee shall be "financially literate". In order to be financially literate, a director must be, at a minimum, able to read and understand financial statements that present a breadth and complexity of accounting issues generally comparable to the breadth and complexity of issues expected to be raised by the Corporation's financial statements.

4. A director appointed by the Board to the Audit Committee shall be a member of the Audit Committee until replaced by the Board or until his or her resignation.

Meetings of the Committee

1. The Audit Committee shall convene a minimum of four times each year at such times and places as may be designated by the Chair of the Audit Committee and whenever a meeting is requested by the Board, a member of the Audit Committee, the auditors, or a senior officer of the Corporation. Meetings of the Audit Committee shall correspond with the review of the quarterly financial statements. Such period reviews of the financial statements shall also include management's discussion and analysis of the results of the Corporation in the respective period and any related disclosure material such as press releases, business acquisition reports, required certificates from management regarding accuracy and completeness of disclosure of financial information and internal financial control systems and any applicable report of the external auditor on such certificates.

2. Notice of each meeting of the Audit Committee shall be given to each member of the Audit Committee and to the auditors, who shall be entitled to attend each meeting of the Audit Committee and shall attend whenever requested to do so by a member of the Audit Committee.

3. The agenda for meetings of the Audit Committee shall be approved in advance by the Chair of the Audit Committee. Notice of a meeting of the Audit Committee shall:

    (a) be in writing;

    (b) state the nature of the business to be transacted at the meeting in reasonable detail;

    (c) to the extent practicable, be accompanied by copies of documentation to be considered at the meeting; and

    (d) be given at least two business days prior to the time stipulated for the meeting or such shorter period as the members of the Audit Committee may permit.

4. A quorum for the transaction of business at a meeting of the Audit Committee shall consist of a majority of the members of the Audit Committee. However, it shall be the practice of the Audit Committee to require review, and, if necessary, approval of certain important matters by all members of the Audit Committee.

5. A member or members of the Audit Committee may participate in a meeting of the Audit Committee by means of such telephonic, electronic or other communication facilities, as permits all persons participating in the meeting to communicate adequately with each other. A member participating in such a meeting by any such means is deemed to be present at the meeting.

6. In the absence of the Chair of the Audit Committee, the members of the Audit Committee shall choose one of the members present to be Chair of the meeting. In addition, the members of the Audit Committee shall choose one of the persons present to be the Secretary of the meeting.

7. The Chairman of the Board, senior management of the Corporation and other parties may be invited to attend meetings of the Audit Committee; however the Audit Committee (i) shall meet with the external auditors independent of management as necessary, in the sole discretion of the Committee, but in any event, not less than quarterly; and (ii) should meet separately with management; and (iii) may meet separately as a committee.

8. Minutes shall be kept of all meetings of the Audit Committee and shall be signed by the Chair and the Secretary of the meeting and shall be available to all members of the Audit Committee.

Duties and Responsibilities of the Committee

1. The Audit Committee's primary duties and responsibilities are to:

    (a) review with management the identification and monitoring by management of the principal risks that could impact the financial reporting of the Corporation;

    (b) monitor the integrity of the Corporation's financial reporting process and system of internal controls regarding financial reporting and accounting compliance;

(c) monitor the independence and performance of the Corporation's external auditors. The Corporation's external auditors are ultimately accountable to the Audit Committee and the Board and the external auditors shall report directly to the Audit Committee;

(d) deal directly with the external auditors to approve external audit plans, other (non-audit) services (if any) and fees;

(e) directly oversee the external audit process and results and resolve any disagreements between management and the external auditor regarding financial reporting;

(f) provide an avenue of communication among the external auditors, management and the Board; and

(g) ensure that an effective "whistle blowing" procedure exists to permit stakeholders to express any concerns regarding accounting or financial matters to an appropriately independent individual.

2. The Audit Committee shall have the authority to:

(a) inspect any and all of the books and records of the Corporation, its subsidiaries and affiliates;

(b) discuss with the management and senior staff of the Corporation, its subsidiaries and affiliates, any affected party and the external auditors, such accounts, records and other matters as any member of the Audit Committee considers necessary and appropriate;

(c) engage independent counsel and other advisors as it determines necessary to carry out its duties and approve the engagement letter for audit services to be provided by the external auditors or affiliates, together with estimated fees; and

(d) to set and pay the compensation for any advisors employed by the Audit Committee.

3. The Audit Committee shall, at the earliest opportunity after each meeting, report to the Board the results of its activities and any reviews undertaken and make recommendations to the Board as deemed appropriate.

4. The Audit Committee shall:

(a) evaluate the independence and performance of the external auditors and annually recommend to the Board the appointment of the external auditor and the compensation of the external auditors;

(b) consider the recommendations of management in respect of the appointment of the external auditors;

(c) review the audit plan with the Corporation's external auditors and with management;

(d) discuss with management and the external auditors any proposed changes in major accounting policies or principles, the presentation and impact of significant risks and uncertainties and key estimates and judgments of management that may be material to financial reporting;

(e) review with management and with the external auditors significant financial reporting issues arising during the most recent fiscal period and the resolution or proposed resolution of such issues;

(f) review and resolve any problems experienced or concerns expressed by the external auditors in performing an audit, including any restrictions imposed by management or significant accounting issues on which there was a disagreement with management;

(g) review with senior management the process of identifying, monitoring and reporting the principal risks affecting financial reporting;

(h) consider and review with management, the internal control memorandum or management letter containing the recommendations of the external auditors and management's response, if any, including an evaluation of the adequacy and effectiveness of the internal financial controls of the Corporation and subsequent follow-up to any identified weaknesses;

(i) review, and if appropriate, recommend for approval by the Board, the audited annual financial statements, management discussion and analysis and related documents in conjunction with the report of the external auditors. In conjunction with the review of the year end audited financial statements, or as circumstances require, the Audit Committee shall review the year end oil and gas reserves report of the Corporation, as prepared by the Corporation's independent reserves evaluator;

(j) review the quarterly unaudited financial statements, management's discussion and analysis and related documents, including the quarterly review report as prepared by the external auditors and, if appropriate, recommend for approval by the Board, the quarterly unaudited financial statements, management's discussion and analysis and related documents;

(k) before release, review and, if appropriate, recommend for consideration and approval by the Board, all public disclosure documents containing audited or unaudited financial information, including annual and quarterly financial statements, management discussion and analysis, annual reports, annual information forms and press releases;

(l) oversee any of the financial affairs of the Corporation, its subsidiaries and affiliates, and, if deemed appropriate, make recommendations to the Board, external auditors or management;

(m) pre-approve all non-audit services to be provided to the Corporation, its subsidiaries and affiliates by the external auditors;

(n) approve the engagement letter for non-audit services to be provided by the external auditors or affiliates, together with estimated fees, and considering the potential impact of such services on the independence of the external auditors;

(o) when there is to be a change of external auditors, review all issues and provide documentation related to the change, including the information to be included in the Change of Auditors Notice and documentation required pursuant to National Instrument 51-102 (or any successor legislation) and the planned steps for an orderly transition period;

(p) review all reportable events, including disagreements, unresolved issues and consultations, as defined by applicable securities laws, on a routine basis, whether or not there is to be a change of external auditors;

(q) review with management at least annually, the financing strategy and plans of the Corporation; and

(r) receive reports and certificates from management with respect to compliance with financial, regulatory, taxation and continuous disclosure requirements.

5. The Audit Committee shall review the amount and terms of any insurance to be obtained or maintained by the Corporation with respect to risks inherent in its operations and potential liabilities incurred by the directors or officers in the discharge of their duties and responsibilities.

6. The Audit Committee shall approve the appointments of the Chief Financial Officer and any key financial managers who are involved in the financial reporting process.

7. The Audit Committee shall enquire into and determine the appropriate resolution of any conflict of interest in respect of audit or financial matters, which are directed to the Audit Committee by any member of the Board, a securityholder of the Corporation, the external auditors, or senior management.

8. The Audit Committee shall periodically review with management the need for an internal audit function.

9. The Audit Committee shall review the Corporation's accounting and reporting of environmental costs, liabilities and contingencies.

10. The Audit Committee shall establish and maintain procedures for:

(a) the receipt, retention and treatment of complaints received by the Corporation regarding accounting controls, or auditing matters; and

(b) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

11. The Audit Committee shall review and approve the Corporation’s hiring policies regarding employees and former employees of the present and former external auditors or auditing matters.

12. The Audit Committee shall review with the Corporation’s legal counsel as required but at least annually, any legal matter that could have a significant impact on the Corporation’s financial statements, and any enquiries received from regulators, or government agencies.

13. In reference to the discharge of the duties of the Audit Committee members under this Charter, each member shall be obliged only to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. Nothing in this Charter is intended, or may be construed, to impose on any member of the Audit Committee a standard of care or diligence that is in any way more onerous or extensive than the standard to which all Board members are subject.

14. The Audit Committee shall assess, on an annual basis, the adequacy of this Charter and the performance of the Audit Committee.