Hemisphere energy corporation

ANNUAL INFORMATION FORM

For the year ended December 31, 2014

April 21, 2015

TABLE OF CONTENTS

APPENDICES

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrels	Mcf	thousand cubic feet
bbl/d	barrels per day	Mcf/d	thousand cubic feet per day
bopd	barrels of oil per day	MMcf	million cubic feet
boe	barrels of oil equivalent	MMbtu	million British thermal units
boe/d	boe per day	Bcf	billion cubic feet
Mboe	thousand barrels of oil equivalent	GJ	gigajoule
Mbbl	thousand barrels		
NGL	natural gas liquids		

Other	
M$	thousands of dollars
$/boe	dollar per barrel of oil equivalent
ha	hectare
3D	three dimensional
API	American Petroleum Institute
ºAPI	specific gravity of crude oil measured on the API gravity scale
AECO	Alberta Energy Company
M^3	Cubic metres
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
W.I.	working interest

BARREL OF OIL EQUIVALENCY

Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

CONVERSIONS

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbl	cubic metres	0.159
cubic metres	bbl	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
gigajoules	MMbtu	0.950
MMbtu	gigajoules	1.0526

CURRENCY

All amounts are expressed in Canadian dollars unless otherwise stated.

FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein and the documents incorporated by reference herein including, without limitation, financial and business prospects and financial outlook, reserve and production estimates, drilling plans, activities to be undertaken in various areas, timing of drilling, recompletion and tie-in of wells, tax horizon, timing of development of undeveloped reserves, commodity prices and foreign exchange rates, planned capital expenditures, the timing thereof and the method of funding may be forward-looking statements which reflect management's expectations regarding future plans and intentions, growth, results of operations, performance and business prospects and opportunities. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be 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, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, changes in environmental or other legislation, reliance on key management personnel, changes in general economic and business conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and the risk factors outlined under "*Risk Factors*" and elsewhere herein. The recovery and reserve estimates of Hemisphere Energy Corporation's ("Hemisphere" or the "Company") reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. In addition, forward-looking statements may include statements attributable to third party industry sources. There can be no assurances that the plans, intentions or expectations upon which such forward-looking statements are based will occur.

Forward-looking statements and information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Hemisphere believes that the expectations reflected in such forward-looking statements and information are reasonable, undue reliance should not be placed on forward-looking statements because Hemisphere can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Hemisphere operates; the timely receipt of any required regulatory approvals; the ability of Hemisphere to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results, the ability of the operator of the projects which Hemisphere has an interest in to operate the project in a safe, efficient and effective manner; the ability of Hemisphere to obtain financing on acceptable terms; well production rates and decline rates; the ability to replace and expand the oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Hemisphere to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Hemisphere operates; and the ability of Hemisphere to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect Hemisphere's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the System for Electronic Document Analysis and Retrieval ("SEDAR") at www.sedar.com and Hemisphere's website at www.hemisphereenergy.ca.

Although the forward-looking statements and information contained herein are based upon what management believes to be reasonable assumptions, management cannot give assurance that actual results will be consistent with such forward-looking statements and information. Investors should not place undue reliance on forward-looking statements and information. These forward-looking statements and information are made as of the date hereof and Hemisphere assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward-looking statements and information contained herein or the documents incorporated herein by reference concerning the oil and gas industry and Hemisphere's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry, which Hemisphere believes to be reasonable. However, this data is inherently imprecise. While Hemisphere 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.

The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement. The forward-looking statements included in this Annual Information Form ("AIF") are made as of the date of this AIF and the Company undertakes no obligation to publicly update such forward-looking statements to reflect new information, subsequent events or otherwise unless required by applicable securities laws.

DESCRIPTION OF THE COMPANY

General

Hemisphere Energy Corporation was incorporated under the laws of the Province of British Columbia on March 6, 1978 and is governed by the *Business Corporations Act* (British Columbia) (the “BCBCA”). The Company does not have any subsidiaries. Hemisphere’s head office is located at Suite 2000, 1055 West Hastings Street, Vancouver, British Columbia V6E 2E9 and its registered office is located at 2900-550 Burrard Street, Vancouver, British Columbia V6C 0A3.

Hemisphere is a producing oil and gas company focused on developing conventional oil assets with low risk drilling opportunities. The Company has production in the Jenner and Atlee Buffalo areas of southeast Alberta and the Trutch area of northeast British Columbia. Hemisphere plans continual growth in production, reserves and cash flow by drilling existing projects and executing strategic acquisitions. Hemisphere trades on the TSX Venture Exchange ("TSX-V") as a Tier 1 issuer under the symbol “HME”.

History of the Company

Ten months ended December 31, 2012

On June 14, 2012, the Company entered into a seismic option and farm-in agreement in the Jenner area which included initial obligations to acquire 3D seismic data and the option to drill a test well with the potential to acquire additional 3D seismic and drill additional wells to earn a maximum of 6.5 sections.

On November 16, 2012, the Company filed a Notice of Change in Year-End under National Instrument 51-102 - *Continuous Disclosure Obligations* ("NI 51-102") changing the Company’s fiscal year-end from February 28 to December 31 to better align financial reporting with the calendar year and industry peers. The transition year from March 1, 2012 to December 31, 2012 included reporting the nine months ended November 30, 2012, followed by the ten months ended December 31, 2012.

On December 20, 2012, the Company closed the first tranche of a non-brokered private placement resulting in the issuance of 1,829,300 units for gross proceeds of $1,189,045. Each unit consisted of one common share and one-half of a non-transferable warrant entitling the holder to purchase one common share at the price of $0.90 until December 20, 2013.

During the year, Hemisphere successfully drilled eight oil wells (7 horizontal and 1 vertical). The Company also expanded its landholdings through Crown land sales, acquiring 2.25 sections (1,440 acres) in southeast Alberta. Existing facilities at Jenner were upgraded, adding a heated free-water-knockout separator for greater fluid handling capacity and reduction of operating costs.

Fiscal year ended December 31, 2013

On January 25, 2013, the Company closed the second and final tranche of a non-brokered private placement resulting in the issuance of 86,900 units for gross proceeds of $56,485. Each unit consisted of one common share and one-half of a non-transferable warrant entitling the holder to purchase one common share at the price of $0.90 until January 25, 2014.

On April 24, 2013, the Company increased its credit facility from $5.5 million to $9.5 million (the "Credit Facility") as a result of reserve additions and production increases from its 2012 drilling activity.

On May 14, 2013, Hemisphere successfully graduated to Tier 1 on the TSX-V. Tier 1 is the premier tier and is reserved for the most advanced issuers with the most significant financial resources on the TSX-V.

On October 16, 2013, the Company entered into a formal letter of intent with an intermediate Canadian producer to purchase certain oil and gas assets in the Atlee Buffalo area of southeast Alberta. This acquisition included 100% working interest in 8.25 sections of contiguous land spanning two large Glauconitic oil pools at a cost of $3.35 million and an effective date of June 1, 2013. This acquisition subsequently closed on November 18, 2013 and was funded by the Credit Facility, which was increased to $10.5 million contemporaneously with the closing of the acquisition.

On December 10, 2013, Hemisphere closed a Bought Deal Equity Financing (the "2013 Financing") with a syndicate of underwriters for aggregate gross proceeds to the Company of $4.3 million to accelerate its capital program focused on Jenner and the newly acquired Atlee Buffalo property. The 2013 Financing resulted in the issuance of 4,182,550 units, comprised of one common share and one half of one warrant entitling the holder to purchase one common share at the price of $0.75 until December 10, 2014, and 3,077,000 common shares issued on “CEE flow-through” basis.

During 2013, Hemisphere successfully drilled two horizontal oil wells in North Jenner. The Company also expanded its landholdings through Crown land sales, acquiring 13.75 sections (8,800 acres) in southeast Alberta. Hemisphere upgraded its main oil battery by increasing its water handling capacity and debottlenecking its oil processing system as a means to optimize fluid rates at a number of existing wells and increase base oil production. Additionally, Hemisphere added a gas sweetening tower which removes H_2S (hydrogen sulfide) from the gas stream allowing the Company to meet third party pipeline specifications and send solution gas to sales.

Fiscal year ended December 31, 2014

On March 13, 2014, the Company announced its Board of Directors approved the adoption of an Advance Notice Policy (the "Policy"). The purpose of the Policy is to: (i) facilitate an orderly and efficient annual general or, where the need arises, special meeting, process, (ii) ensure that all shareholders receive adequate notice of the director nominations and sufficient information regarding all director nominees, and (iii) allow shareholders to register an informed vote after having been afforded reasonable time for appropriate deliberation. The Policy was ratified by the shareholders of the Company at the Company’s annual general and special meeting held June 6, 2014.

On May 14, 2014, Hemisphere closed a Bought Deal Equity Financing (the "2014 Financing") with a syndicate of underwriters for aggregate gross proceeds of $10.0 million to accelerate its capital program focused on Atlee Buffalo and Jenner. The 2014 Financing resulted in the issuance of 13,333,500 common shares.

On September 9, 2014, the Company announced the promotion of Mr. Ian Duncan from Vice President of Engineering to Chief Operating Officer and the appointment of Ms. Ashley Ramsden-Wood to Vice President of Engineering.

On October 7, 2014, the Company appointed Mr. Richard Wyman to the Board of Directors.

Effective November 28, 2014, the Company successfully increased the Credit Facility to $15.0 million as a result of the drilling activities and production growth from the Company's 2014 capital program.

During the year, Hemisphere successfully drilled 10 horizontal oil wells in Atlee Buffalo, two horizontal oil wells in Jenner, and one vertical test well in Jenner. The Company expanded its landholdings through Crown land sales acquiring 2,560 hectares in southeast Alberta. Hemisphere installed a solution gas compressor at the Company's main production facility in Jenner to increase volume through-put. The Company also acquired 3D seismic in each of the Atlee Buffalo and Jenner areas.

Significant Acquisitions

The Company did not make any significant acquisitions during 2014.

Competition

The oil and gas industry is competitive in all its phases. The Company competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Company's competitors include resource companies that have greater financial resources, staff and facilities than those of the Company. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. The Company believes that its competitive position is 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. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances.

The Company's operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including, but not limited to, weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on the Company's financial condition and such effect could be material. See *"Risk Factors"*.

Environmental Regulation

The oil and gas industry is subject to environmental regulations pursuant to applicable legislation. Such legislation provides for restrictions and prohibitions on release or emission of various substances produced in association with certain oil and gas industry operations, and requires that well and facility sites be abandoned and reclaimed to the satisfaction of environmental authorities. No assurance can be given that the application of environmental laws to the business and operations of the Company will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Company's financial condition, results of operations or prospects. See *"Risk Factors"*.

Human Resources

As at December 31, 2014, Hemisphere had eight full-time head office employees and one full-time field employee. Additionally, the Company had five part-time consultants and two full-time field contractors.

Specialized Skill and Knowledge

The Company relies on specialized skills and knowledge to gather, interpret and process geophysical data, operate production facilities and numerous additional activities required to produce oil and natural gas. The Company has employed a strategy of contracting consultants and other service providers to supplement the skills and knowledge of its permanent staff in order to provide the specialized skills and knowledge to undertake its oil and natural gas operation effectively.

Risk Factors

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Company's other public filings before making an investment decision. The risks set out below are not an exhaustive list, nor should they be taken as a complete summary or description of all the risks associated with the business of the Company and the oil and natural gas business generally.

Exploration, Development and Production Risks

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

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

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

Global Economic Downturn

The market events and conditions witnessed over the past several years, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to and reductions in commodity prices. The continued uncertainty in the global economic situation means that the Company, along with all other oil and gas entities, may continue to face restricted access to capital and increased borrowing costs. To the extent that external sources of capital become limited or unavailable or available on unfavourable terms, our ability to make capital investments and maintain existing properties may be constrained, and, as a result, the Company’s business, financial condition, results of operations and cash flow may be materially adversely affected.

Oil and natural gas prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, the actions of other oil and natural gas producing countries and the ongoing global credit and liquidity concerns.

Volatility of Market Price of Common Shares

The market price of the common shares of the Company may fluctuate due to a variety of factors relative to Hemisphere’s business, including announcements of new developments, fluctuations in Hemisphere’s operating results, sales of the common shares in the marketplace, failure to meet analysts’ expectations, any public announcements made in regards to the Company, the impact of various tax laws or rates and general market conditions or the worldwide economy. In recent years, stock markets have experienced significant price fluctuations, which have been unrelated to the operating performance of the affected companies. There can be no assurance that the market price of the common shares of the Company will not experience significant fluctuations in the future, including fluctuations that are unrelated to the Company’s performance. Volatility may affect the ability of holders to sell the common shares of the Company at an advantageous price.

Prices, Markets and Marketing

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

The prices of oil and natural gas may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Company's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of the Company's reserves. The Company might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Company's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Company. These factors include economic conditions, in the United States and Canada, the actions of the Organization of the Petroleum Exporting Countries ("OPEC"), governmental regulation, sanctions imposed on certain oil producing nations by other countries, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Oil prices are expected to remain volatile and may decline in the near future as a result of global excess supply due to the increased growth of shale oil production in the United States, the decline in global demand for exported crude oil commodities and OPEC's recent decisions pertaining to the oil production of OPEC member countries, among other factors. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Company's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploration projects.

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Operational Dependence

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

Project Risks

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

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

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

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development activities.

Reserve Estimates

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

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

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

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

Competition

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

Regulatory

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

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material, the suspension or revocation of necessary licenses and permits, and civil liability for pollution damage. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge. Although the Company believes that it will be in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Company's business, financial condition, results of operations and prospects. There has been much public debate with respect to Canada's and Provincial Governments' respective strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases could have a material impact on the nature of oil and natural gas operations, including those of the Company. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and the evolving legislative requirements, it is not possible to predict the impact on the Company and its operations and financial condition. See "*Industry Conditions – Environmental and Climate Change Regulation*".

Substantial Capital Requirements

The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Company's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Company to additional access to capital risk. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Additional Funding Requirements

The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Company may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Company's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Company's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Company's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Company. Continued uncertainty in domestic and international credit markets could materially affect the Company's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Company's ability to execute its business strategy and on its business, financial condition, results of operations and prospects**.**

Changes to the Royalty Regime

There can be no assurance that the governments of Alberta, British Columbia or Canada will not adopt a new royalty regime or modify the methodology of royalty calculations that would increase the royalties paid by the Company. An increase of royalty rates would reduce the Company's earnings and make certain of the Company's projects uneconomic. See "*Industry Conditions - Provincial Royalties and Incentives*".

Issuance of Debt

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

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/United States dollar exchange rate, which will fluctuate over time. Material increases in the value of the Canadian dollar negatively impact the Company's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Company's reserves as determined by independent evaluators.

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

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

Hedging

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

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Company's claim which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company’s actual interest in properties may, therefore, vary from its records.

Insurance

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

Geo-Political Risks

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

In addition, the Company's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Company's properties, wells or facilities are the subject of a terrorist attack, it may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company does not have insurance to protect against the risk from terrorism.

Dilution

The Company may issue additional common shares in the future, which may dilute a shareholders' holding in the Company. The Company's articles permit the issuance of an unlimited number of common shares and shareholders have no pre-emptive rights in connection with such further issuances. The Board of Directors of the Company have the discretion to determine the price and the terms of issue of further issuances of common shares. Also, additional common shares will be issued by the Company on the exercise of stock options under the Company's stock option plan.

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

Management of Growth

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

Expiration of Licences and Leases

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

Seasonality

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

Liability Management

Alberta and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of the Company's deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. See: "Industry Conditions".

Climate Change

The Company's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Company to comply with greenhouse gas ("GHG") emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. Some of the Company's facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Company and its operations and financial condition.

Third Party Credit Risk

The Company may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its oil and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Company, such failures may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program until the Company finds a suitable alternative partner.

Reliance on Key Personnel

The Company's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company does not have any key person insurance in effect for the Company. The contributions of the existing management team to the immediate and near term operations of the Company are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Company.

Forward-Looking Information May Prove Inaccurate

Investors are cautioned not to place undue reliance on forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Income Taxes

The Company files all required income tax returns and believes it is in full compliance with the provisions of the *Income Tax Act* (Canada) and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Company, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Company. Furthermore, tax authorities having jurisdiction over the Company may disagree with how the Company calculates its income for tax purposes or could change administrative practices to Hemisphere's detriment.

Litigation Risks

In the normal course of the Company's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to personal injuries, property damage, property taxes, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company and as a result, could have a material adverse effect on Company's assets, liabilities, business, financial condition and results of operations. Even if the Company prevails in any such legal proceeding, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from the Company's business operations, which could adversely affect its financial condition.

Conflicts of Interest

There are potential conflicts of interest to which some of the directors and officers of the Company will be subject in connection with the operations of the Company. Some of the directors and officers are engaged and will continue to be engaged in the search of oil and gas interests on their own behalf and on behalf of other corporations, and situations may arise where the directors and officers will be in direct competition with the Company.

Conflicts of interest, if any, that arise will be subject to and be governed by procedures prescribed by the BCBCA, which requires a director or officer of a corporation who is a party to or is a director or an officer of or has a material interest in any person who is a party to a material contract or proposed material contract with the Company, to disclose his interest and to refrain from voting on any matter in respect of such contract, unless otherwise permitted under the BCBCA.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Company is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful, such claim may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Company may disclose confidential information relating to the business, operations or affairs of the Company. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put the Company at competitive risk and may cause significant damage to its business. The harm to the Company's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Company will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Dividends

The Company does not currently pay any dividends on its outstanding common shares. Payments of dividends in the future will be dependent on, among other things, the Company's cash flow, results of operations and financial condition, the need for funds to finance ongoing operations and other considerations, as the Board of Directors of the Company considers relevant.

Industry Conditions

The oil and 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 Government of Canada and the Provincial Governments, 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 Company's operations in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing - Oil and Natural Gas

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

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

The NEB is currently undergoing a consultation process to update the regulations governing the issuance of export licences. The NEB has issued, and is currently following, an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications" under Part VI of the National Energy Board Act (Canada).

Provincial governments also regulate the volume of natural gas that may be removed for consumption outside the province of production based on such factors as reserve availability, transportation arrangements, and market considerations.

Gathering and Processing Facilities, Pipeline Systems and Rail

The Company delivers its products through gathering and processing facilities and pipeline systems some of which it does not own and by rail. The amount of oil and natural gas that the Company can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines, and in particular the processing facilities, could result in the Company's inability to realize the full economic potential of its production or in a reduction of the price offered for the Company's production. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Furthermore, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically and it is projected to continue in this upward trend. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could limit the ability to produce and market such production, and therefore western Canadian production may receive discounted pricing. Current pipeline construction projects before various regulatory bodies, if approved, are expected to alleviate this risk, as are numerous projects to increase rail handling and transportation of oil and other liquid hydrocarbons.

The North American Free Trade Agreement

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

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

Provincial Royalties and Incentives

General

Other than relatively small amounts held by private parties and First Nations, natural resources in Canada are owned by each Province, respectively. As such, royalties fall primarily under provincial jurisdiction. Provincial royalty regimes are 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 negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties.

Provincial Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery, and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally, the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Generally, royalty holidays and reductions reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and increase the net income and funds from operations of such producers.

Alberta

In Alberta, producers of oil and natural gas from Crown lands are required to pay annual rental payments, currently at a rate of $3.50 per ha, and make monthly royalty payments in respect of oil and natural gas produced.

Under the current “Alberta Royalty Framework” ("ARF"), royalty rates for oil and natural gas are set by a single sliding rate formula which is applied monthly using separate variables to account for production rates and market prices. The maximum royalty payable under the ARF for oil is 40%, and the maximum royalty payable for natural gas is 36%. The Government of Alberta also levies royalties on volumes of propane, butane, pentanes plus, bitumen and sulphur produced from Crown lands.

There are several incentive programs currently in effect to stimulate oil and gas investment in Alberta. The Natural Gas Deep Drilling Program provides royalty incentives for deep natural gas wells. A new-well incentive program applies to wells beginning production of conventional oil and natural gas and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 barrels or 500 MMcf of natural gas. The Emerging Resource and Technologies Initiative is intended to accelerate technological development and facilitate the development of unconventional resources and applies similar 5% royalty rates to horizontal gas and oil wells, coal bed methane wells and shale gas wells. An Enhanced Oil Recovery program encourages the injection of fluids such as hydrocarbons, carbon dioxide, nitrogen, chemicals and other approved substances for the recovery of additional oil.

Producers of oil and natural gas from freehold lands in Alberta are required to pay a freehold mineral tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands. The freehold mineral tax is levied on an annual basis on calendar year production using a formula that takes into consideration, among other things, the volume of monthly production, a specified rate of tax for both oil and gas and the percentages that the owners hold in the title. On average, the tax levied is 4% of revenues reported from fee simple mineral title properties.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments with respect to the Crown leases (currently at a rate of $7.50 per ha), and make monthly payments in respect of royalties and freehold production taxes due in respect of oil and gas produced from Crown and freehold lands.

The amount payable as a royalty in British Columbia in respect of oil depends on the type of oil, the value of the oil, the quantity of oil produced in a month, and the vintage of the oil. Generally, the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 (“old oil”), between October 31, 1975, and June 1, 1998 (“new oil”), or after June 1, 1998 (“third-tier oil”). The royalty rates are calculated in three stages, which take into account the vintage of the oil, if the oil produced has already been sold and any royalty exempt value applicable. Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 produced, whichever comes first; and the royalties for third-tier oil are the lowest reflecting the higher costs of exploration and extraction that the producers would incur.

The royalty payable on natural gas produced from British Columbia Crown lands is determined by a sliding scale based on a reference price, which is the greater of the average net price obtained by the producer, and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas as an incentive for the production and marketing of natural gas, which might otherwise have been flared.

The Government of British Columbia has several royalty credit and royalty reduction programs intended to increase the competitiveness of low productivity natural gas wells, including the Deep Royalty Credit Program, the Deep Re-Entry Royalty Credit Program, the Deep Discovery Royalty Credit Program, the Coalbed Gas Royalty Reduction and Credit Program, the Marginal Royalty Reduction Program, the Ultra-Marginal Royalty Reduction Program, and the Net Profit Royalty Reduction Program.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 of production, whichever occurs first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program which provides royalty credits for up to 50% of the lesser of the estimated completion cost and the completion cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas.

The Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation was amended effective April 1, 2013 to provide for a 3% minimum royalty on affected wells with deep well/deep re-entry credits. The 3% minimum royalty applies to deep wells when the net royalty payable would otherwise be zero for a production month.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes to the Government of British Columbia. For oil, the level of the freehold production tax is based on the volume of monthly production. For natural gas, the freehold production tax is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas.

Land Tenure

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

Each of the Governments of Alberta and British Columbia has implemented legislation providing for the reversion to the Crown of mineral rights of deep, non-productive geological formations at the conclusion of the primary term of a lease or license. On March 29, 2007, British Columbia's policy of deep rights reversion was expanded for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

In Alberta, for leases and licenses issued subsequent to January 1, 2009, shallow rights reversion is applied at the conclusion of the primary term of the lease or license. Although Alberta Energy had previously announced that shallow rights reversions would be implemented for leases and licences that had been granted prior to January 1, 2009 by the service of reversion notices at the end of their primary terms, in April 2013, it communicated to industry that it was deferring the service of such notices indefinitely.

Environmental and Climate Change Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, which may be amended from time to time. Such legislation provides for restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material, the suspension or revocation of necessary licenses and permits, and civil liability for pollution damage.

Alberta

Environmental legislation in Alberta is consolidated in the *Environmental Protection and Enhancement Act* (Alberta) (the "EPEA") and the *Oil and Gas Conservation Act* (Alberta) (the "OGCA"). The EPEA and OGCA impose environmental standards, reporting and monitoring obligations, and penalties for non-compliance.

The Province of Alberta has a single regulator for upstream oil and gas, oil sands and coal development activity, the Alberta Energy Regulator (the "AER"). The objective is enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners. On June 17, 2013, the AER assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the Oil and Gas Conservation Act ("ABOGCA"). On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development ("AESRD") in respect of the disposition and management of public lands under the *Public Lands Act* (Alberta). On March 29, 2014, the AER assumed the energy related functions and responsibilities of AESRD in the areas of environment and water under the *EPEA* and the *Water Act* (Alberta), respectively. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The restructuring of the agencies implementing regulation has not been accompanied by substantive amendments to the underlying Provincial Government policy or legislation.

The Alberta Land Use Framework (the "ALUF") sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the Government of Alberta. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

The *Alberta Land Stewardship Act* (the "ALSA") was proclaimed in force in Alberta on October 1, 2009 and provides the legislative authority to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, leases, licenses, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

The first regional plan under the ALSA, the Lower Athabasca Regional Plan (the "LARP"), came into effect on September 1, 2012. The LARP covers the northeast corner of Alberta and the entirety of the Athabasca oil sands region. In July 2014, the Government of Alberta approved the South Saskatchewan Regional Plan (the "SSRP") which covers approximately 83,764 square kilometres and includes 45% of the provincial population. The SSRP was released in draft form in 2013. With the implementation of the new Alberta regulatory structure under the AER, AESRD will remain responsible for development and implementation of regional plans. However, the AER will take on some responsibility for implementing regional plans in respect of energy related activities.

The Government of Alberta enacted the *Climate Change and Emissions Management Act* (the "CCEMA") on December 4, 2003, amending it through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020. Facilities in Alberta emitting more than 100,000 tonnes of carbon dioxide equivalent a year are subject to compliance with the CCEMA. As at year-end 2014, Hemisphere did not have an interest in any facilities in Alberta that emit more than 100,000 tonnes of carbon dioxide equivalent per year.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "OGAA") governs conventional oil and gas producers, shale gas producers and other operators of oil and gas facilities. Under the OGAA, the British Columbia Oil and Gas Commission (the "Commission") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for oil and gas activities. The Environmental Protection and Management Regulation establishes the Government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The Commission is required to consider these environmental objectives in deciding whether or not to authorize an oil and gas activity. In addition, the *Petroleum and Natural Gas Act* (British Columbia) requires proponents to obtain various approvals before undertaking exploration or production work. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

In February 2008, the Government of British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. This tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is $30 per tonne of carbon dioxide equivalent. British Columbia is currently undertaking a comprehensive review of the carbon tax, and may or may not make changes to its carbon tax regime. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "Cap and Trade Act") which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations came into force requiring all British Columbia facilities emitting over 10,000 tonnes of carbon dioxide equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of carbon dioxide equivalents per year are required to have their emissions reports verified by a third party. Regulations pertaining to proposed offsets and emissions trading remain in development. As at year-end 2014, Hemisphere did not have an interest in any facilities in British Columbia that emit more than 25,000 tonnes of carbon dioxide equivalent per year.

Federal

Pursuant to the *Jobs, Growth and Long-term Prosperity Act* (the “Prosperity Act”) which received Royal Assent on June 29, 2012, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime that came into force on July 6, 2012. The changes to the environmental legislation under the Prosperity Act are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "Action Plan") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions", was released on March 10, 2008 (the "Updated Action Plan"). The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

Although draft regulations for the implementation of the Updated Action Plan were intended to become binding on January 1, 2010, only regulations pertaining to carbon dioxide emissions from coal-fired generation of electricity have been enacted to date. Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent, if any; the proposals contained in the Updated Action Plan will be implemented.

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

Liability Management Rating Programs

In Alberta, the AER implements the Licensee Liability Rating Program (the "AB LLR Program"). The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The ABOGCA establishes an orphan fund (the "Orphan Fund") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant ("WIP") becomes defunct. The Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licensees and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER.

Effective May 1, 2013, the AER implemented important changes to the AB LLR Program that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. These changes will be implemented over a three-year period with the final phase becoming effective in May of 2015.

On July 4, 2014, the AER introduced the inactive well compliance program (the "IWCP") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 013: Suspension Requirements for Wells ("Directive 013"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within 5 years. As of April 1, 2015, each licensee will be required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020: Well Abandonment.

In British Columbia, the Commission implements the Liability Management Rating ("LMR") Program, designed to manage public liability exposure related to oil and gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the LMR Program, the Commission determines the required security deposits for permit holders under the OGAA. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets will be considered high risk and reviewed for a security deposit. Permit holders who fail to submit the required security deposit within the allotted timeframe may be in non-compliance with the OGAA.

STATEMENT OF RESERVES AND OTHER OIL AND NATURAL GAS INFORMATION

In accordance with National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") and Canadian Oil and Gas Evaluation Handbook reserve definitions, McDaniel & Associates Consultants Ltd. (“McDaniel”) prepared a report for the Company dated March 2, 2015 with an effective date of December 31, 2014 (the "McDaniel Report"). The McDaniel Report evaluated Hemisphere’s oil, NGL and natural gas reserves. All properties evaluated are in Canada and specifically in Alberta and British Columbia.

The tables below are a summary of the oil, NGL and natural gas reserves attributable to Hemisphere’s properties and the net present values of future net revenue attributable to such reserves as evaluated in the McDaniel Report based on forecast price and certain cost assumptions. The tables summarize the data contained in the McDaniel 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 values of future net revenue attributable to 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 McDaniel. It should not be assumed that the undiscounted or discounted net present values of future net revenue attributable to reserves estimated by 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 oil, NGL and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein.

The McDaniel Report is based on certain factual data supplied by the Company and McDaniel’s opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Company to McDaniel. McDaniel accepted this data as presented and neither title searches nor field inspections were conducted.

Readers should review the definitions and information contained in "*Additional Information Relating to Reserve Data*" below in conjunction with the following tables and notes. The recovery and reserve estimates on Hemisphere’s properties described herein are estimates only. The actual reserves on Hemisphere’s properties may be greater or less than those calculated. See "*Risk Factors*".

Summary of Oil and Gas Reserves – Forecast Prices and Costs

	Heavy Oil		Natural Gas		Natural Gas Liquids	
	Gross(1) (Mbbl)	Net(2) (Mbbl)	Gross(1) (MMcf)	Net(2) (MMcf)	Gross(1) (Mbbl)	Net(2) (Mbbl)
Proved						
Developed Producing	930.0	782.2	969.0	879.1	3.8	2.7
Developed Non-Producing	185.3	166.6	148.7	136.6	-	-
Undeveloped	820.2	716.4	405.6	368.2	-	-
Total Proved	**1,935.5**	**1,665.2**	**1,523.4**	**1,383.8**	**3.8**	**2.7**
Probable	1,007.9	818.0	812.1	739.7	1.1	0.8
Total Proved Plus Probable	**2,943.3**	**2,483.2**	**2,335.4**	**2,123.6**	**4.9**	**3.5**

Notes:

(1) Gross reserves are working interest reserves before royalty deductions.

(2) Net reserves include working interest after royalty deductions plus royalty interest reserves.

Summary of Net Present Values of Future Net Revenue – Forecast Prices and Costs

	Before Income Taxes and Discounted at(1)				
(M$)	0%	5%	10%	15%	20%
Proved					
Developed Producing	32,245.1	28,546.5	25,571.7	23,179.8	21,238.0
Developed Non-Producing	4,844.9	4,295.3	3,822.6	3,426.8	3,096.6
Undeveloped	17,609.3	13,883.2	10,930.9	8,598.9	6,746.3
Total Proved	**54,699.2**	**46,725.0**	**40,325.2**	**35,205.5**	**31,080.8**
Probable	**38,429.2**	**28,747.6**	**22,153.6**	**17,555.9**	**14,258.2**
Total Proved Plus Probable	**93,128.4**	**75,472.6**	**62,478.8**	**52,761.4**	**45,339.1**

Note:

(1) Costs associated with extraction of natural gas products have been deducted from the natural gas revenues.

	After Income Taxes and Discounted at				
(M$)	0%	5%	10%	15%	20%
Proved					
Developed Producing	32,245.1	28,546.5	25,571.7	23,179.8	21,238.0
Developed Non-Producing	4,844.9	4,295.3	3,822.6	3,426.8	3,096.6
Undeveloped	13,618.9	10,539.8	8,093.0	6,162.5	4,633.5
Total Proved	**50,708.9**	**43,381.6**	**37,487.2**	**32,769.1**	**28,968.1**
Probable	29,425.9	21,852.6	16,705.9	13,137.4	10,594.6
Total Proved Plus Probable	**80,134.8**	**65,234.1**	**54,193.1**	**45,906.5**	**39,562.7**

($/boe)	Unit Value **Before** Income Taxes Discounted at 10%/year(1)
Proved	
Developed Producing	23.35
Developed Non-Producing	18.19
Undeveloped	12.31
Total Proved	**18.39**
Probable	19.36
Total Proved Plus Probable	**18.72**

Note:

(1) Gross reserves are working interest reserves before royalty deductions.

Total Future Net Revenue Undiscounted – Forecast Prices and Costs

(M$)	Sales Revenue[1]	Royalties[2]	Operating Costs	Total Development Costs	Well Abandon-ment Costs	Future Net Revenue Before Tax	Income Taxes	Future Net Revenue After Tax
Proved	147,763	20,165	52,118	18,831	1,950	54,699	3,990	50,709
Proved Plus Probable	236,753	36,059	82,187	23,083	2,296	93,128	12,994	80,135

Notes:

(1) Sales Revenue includes all non-producing income.

(2) Royalties include any net profits interests paid.

Net Present Value of Future Net Revenue by Production Group – Forecast Prices and Costs

	Net Present Value of Future Net Revenue Before Income Taxes[1] Discounted at 10%/Year (M$)	Unit Values Before Income Taxes[2] Discounted at 10%/Year ($/bbl; $/Mcf)
Proved		
Heavy Oil	40,241	24.17
Non-Associated Gas (Including Byproducts)	84	0.51
Proved Plus Probable		
Heavy Oil	62,301	25.09
Non-Associated Gas (Including Byproducts)	178	0.48

Notes:

(1) Processing income is included where applicable.

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

Summary of Pricing and Inflation Rate Assumptions – Forecast Prices and Costs

McDaniel employed the following pricing, exchange rate and inflation rate assumptions in estimating the Company's reserves data using forecast prices and costs as of January 1, 2015.

Year	Oil			Natural Gas	NGL			Inflation (%)	US/Cdn Exchange Rate ($US/$Cdn)
	WTI Crude Oil ($US/bbl)	Edmonton Light Crude Oil ($Cdn/bbl)	Western Canadian Select Crude Oil ($Cdn/bbl)	Alberta AECO Spot Price ($Cdn/MMBtu)	Edmonton Condensate and Natural Gasolines ($Cdn/bbl)	Edmonton Butanes ($Cdn/bbl)	Edmonton Propane ($Cdn/bbl)		
2015	65.00	68.60	57.60	3.50	72.60	52.80	26.10	2.0	0.86
2016	75.00	83.20	69.90	4.00	87.30	67.00	36.50	2.0	0.86
2017	80.00	88.90	74.70	4.25	93.10	71.60	44.50	2.0	0.86
2018	84.90	94.60	79.50	4.50	98.80	76.20	49.30	2.0	0.86
2019	89.30	99.60	83.70	4.70	103.90	80.30	51.80	2.0	0.86
2020	93.80	104.70	87.90	5.00	109.10	84.40	54.70	2.0	0.86
2021	95.70	106.90	89.80	5.30	111.40	86.10	56.20	2.0	0.86
2022	97.60	109.00	91.60	5.50	113.60	87.80	57.50	2.0	0.86
2023	99.60	111.20	93.40	5.70	115.90	89.60	58.90	2.0	0.86
2024	101.60	113.50	95.30	5.90	118.30	91.50	60.30	2.0	0.86
2025	103.60	115.70	97.20	6.00	120.60	93.20	61.50	2.0	0.86
2026	105.70	118.00	99.10	6.10	123.00	95.10	62.70	2.0	0.86
2027	107.80	120.40	101.10	6.25	125.50	97.00	64.00	2.0	0.86
2028	110.00	122.80	103.20	6.35	128.00	99.00	65.20	2.0	0.86
2029	112.20	125.30	105.30	6.50	130.60	101.00	66.60	2.0	0.86
Thereafter	Escalation Rate of 2%/year							2.0	0.86

Note:
Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale.

The weighted average realized sales prices for Hemisphere for the year ended December 31, 2014 were $73.87/bbl for oil, $54.85/bbl for NGLs and $4.08/Mcf for natural gas.

Reconciliation of Company Gross Reserves (Before Royalty) by Principal Product Type – Forecast Prices and Costs

The following table sets forth a reconciliation of the Company's gross reserves as at December 31, 2014, derived from the McDaniel Report using forecast prices and cost estimates, reconciled to the Company's gross reserves as at December 31, 2013.

	Heavy Oil			**Associated and Non-Associated Gas**			**Natural Gas Liquids**			**Boe**		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
Dec. 31, 2013	**1,135.4**	**696.5**	**1,831.9**	**801.0**	**597.2**	**1,398.2**	**3.9**	**4.9**	**8.8**	**1,272.8**	**800.9**	**2,073.7**
Extensions	838.4	508.0	1,346.4	706.2	357.8	1,064.0	-	-	-	956.1	567.6	1,523.7
Infill Drilling	-	-	-	-	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	157.5	(201.0)	(43.5)	232.8	(142.9)	89.9	0.5	(3.8)	(3.3)	196.8	(228.6)	(31.8)
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	17.0	4.4	21.0	-	-	-	-	-	-	17.0	4.4	21.4
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	212.8	-	212.8	216.6	-	216.6	0.6	-	0.6	249.5	-	249.5
Dec. 31, 2014	**1,935.5**	**1,007.9**	**2,943.4**	**1,523.4**	**812.1**	**2,335.5**	**3.8**	**1.1**	**4.9**	**2,193.2**	**1,144.4**	**3,337.6**

Undeveloped Reserves

Undeveloped reserves were attributed in accordance with the standards and procedures in the Canadian Oil and Gas Evaluation Handbook.

The following table sets out the Company's gross reserves, first attributed by year.

	Heavy Oil		Natural Gas		Natural Gas Liquids	
	First Attributed Gross (Mbbl)	Booked Gross (Mbbl)	First Attributed Gross (MMcf)	Booked Gross (MMcf)	First Attributed Gross (Mbbl)	Booked Gross (Mbbl)
Proved Undeveloped						
February 29, 2012(1)	90.0	90.0	-	-	-	-
December 31, 2012(1)	157.4	243.0	-	-	-	-
December 31, 2013	334.1	592.6	157.8	157.8	-	-
December 31, 2014	468.5	820.2	371.0	405.6	-	-
Probable Undeveloped						
February 29, 2012(1)	175.0	175.0	3.0	27.0	-	-
December 31, 2012(1)	69.9	190.3	-	-	-	-
December 31, 2013	327.3	504.3	117.4	117.4	-	-
December 31, 2014	365.5	571.9	227.6	238.2	-	-

Note:
(1) Year-end reporting date changed from February 29 to December 31.

Proved undeveloped reserves are generally those reserves related to infill wells that have not yet been drilled or wells further away from gathering systems requiring relatively high capital to bring on production. Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. This also includes the probable undeveloped wedge from the proved undeveloped locations.

The Company currently plans to pursue the development of its proven and probable undeveloped reserves within the next two years through ordinary course capital expenditures. However, the Company may choose to delay development depending on a number of circumstances, including the existence of higher priority expenditures and prevailing commodity prices and cash flow.

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 or economic data. These estimates may change substantially as additional data from ongoing development activities and production performance become available and as economic conditions impacting oil and natural gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. Hemisphere's reserves are evaluated by McDaniel, an independent engineering firm.

As circumstances change and additional data becomes 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 either be positive or negative.

Future Development Costs

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

	Forecast Prices and Costs	
	Proved Reserves (M$)	Proved Plus Probable Reserves (M$)
2015	8,065	8,221
2016	10,765	13,764
2017	-	1,098
2018	-	-
2019	-	-
Remaining Years	-	-
Total Undiscounted	**18,831**	**23,083**

Hemisphere typically has available three sources of funding to finance its capital expenditure program: internally generated cash flow from operations, debt financing when appropriate and new equity issues, if available on favourable terms.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

The determination of oil and natural 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 reserve definitions.

"Associated Gas" means the gas cap overlying a crude oil accumulation in a reservoir.

"Crude oil" or **"oil"** 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.

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

"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.

"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.

"Fair market value" means the price at which a purchaser seeking an economic and commercial return on investment would be willing to buy, and a vendor would be willing to sell, where neither is under compulsion to buy or sell and both are competent and have reasonable knowledge of the facts.

"Future net revenue" means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using constant prices and costs or forecast prices and costs.

"Gas" or **"Natural Gas"** 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.

"Gross" means:

(a) in relation to the Company's interest in production or reserves, its "Company gross reserves", which are the Company's interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Company;
(b) in relation to wells, the total number of wells in which the Company has an interest; and
(c) in relation to properties, the total area of properties in which the Company has an interest.

"Natural Gas Liquids" means those hydrocarbon components that can be removed 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 Company's interest in production or reserves, its working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company's royalty interest in production or reserves;
(b) in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and
(c) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

"Non-Associated Gas" means an accumulation of natural gas in a reservoir where there is no crude oil.

"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 provided plus probable reserves. Possible reserves have not been considered in this report.

"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.

"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.

"Remaining Recoverable Reserves" means the total remaining recoverable reserves associated with the acreage in which the Company has an interest.

"Solution Gas" means gas dissolved in crude oil.

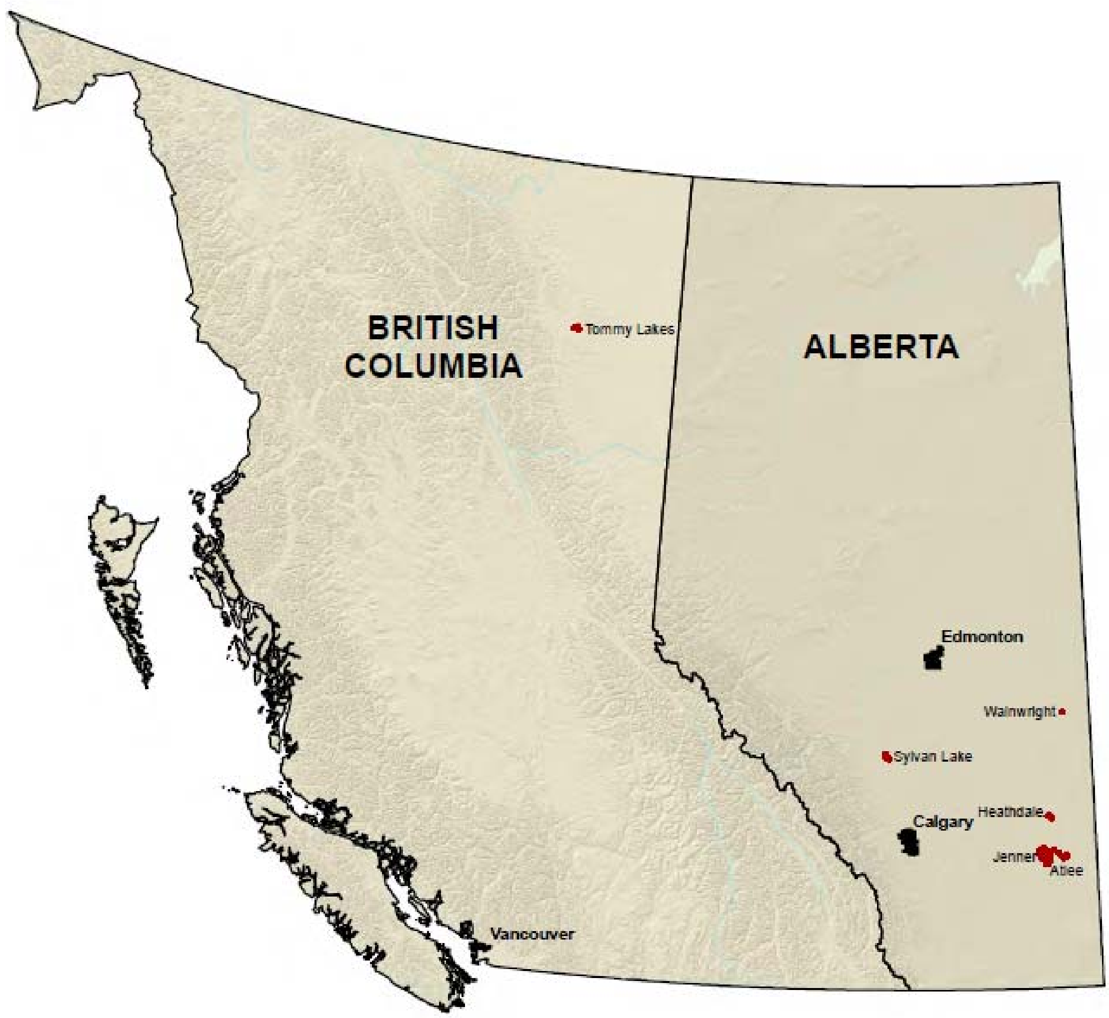
"Undeveloped Reserves" are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable, 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.

OTHER OIL AND GAS INFORMATION

Description of Oil and Gas Properties

Hemisphere's oil and gas properties at December 31, 2014 are located in Alberta and British Columbia. The following map identifies the location of the Company's assets:



Core Assets

The Company has two producing core assets located in southeast Alberta.

Jenner

Jenner is located 100 kilometres northwest of Medicine Hat. Hemisphere first entered the area in 2010 and owns 28,360 gross acres (25,650 net acres) as of December 31, 2014. The property has eight oil pools defined by 3D seismic and 30 identified locations. There are two, Hemisphere owned and operated, oil processing and water disposal facilities in Jenner with the capability for expansion.

Atlee Buffalo

Atlee Buffalo is located 25 kilometres northeast of Jenner. Hemisphere made its first acquisition in the area in late 2013 and owns 7,360 gross acres (7,192 net acres) as of December 31, 2014. The property has two oil pools delineated by vertical wells and 65 identified locations. Based on internal mapping, Atlee Buffalo has high original-oil-in-place and low current recovery factors.

Non-core Assets

Trutch (Tommy Lakes) is located 250 kilometres northwest of Fort St. John, British Columbia. The Company owns 35,612 gross acres (21,525 net acres) as of December 31, 2014, which includes non-operated wells producing liquids rich natural gas.

Hemisphere also has various working interests in non-core assets located in southern Alberta.

Oil and Gas Wells

The following table summarizes Hemisphere's interest as at December 31, 2014 in wells that are producing and non-producing:

	Producing Wells				**Non-Producing Wells**			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta								
Atlee Buffalo	15	14.7	2	2.0	17	16.7	4	4.0
Jenner	19	18.4	4	4.0	20	20.0	-	-
Sylvan Lake	-	-	4	0.6	-	-	6	1.7
Wainwright	-	-	-	-	-	-	1	0.6875
British Columbia								
Trutch	-	-	4	1.4	-	-	2	1.5
Total	**34**	**33.1**	**14**	**8.0**	**37**	**36.7**	**13**	**7.8875**

Exploration and Drilling Activity

The following table summarizes the gross and net exploration and development wells in which Hemisphere participated during the year ended December 31, 2014:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	-	-	12	12.0
Gas	-	-	-	-
Service Well	-	-	-	-
Stratigraphic Test Well	1	1.0	-	-
Dry Hole	-	-	-	-
Total	**1**	**1.0**	**12**	**12.0**

Production History

	Three Months Ended			
	March 31, 2014 Q1	June 30, 2014 Q2	Sept. 30, 2014 Q3	Dec. 31, 2014 Q4
Average daily production				
Oil (bbl/d)	488	454	624	763
Natural gas (Mcf/d)	473	584	594	720
NGL (bbl/d)	-	2	2	3
Combined (boe/d)	567	553	725	885
Average sales prices				
Oil ($/bbl)	76.90	85.72	77.97	61.66
Natural gas ($/Mcf)	4.42	4.64	3.97	3.52
NGL ($/bbl)	-	68.24	59.86	39.72
Combined ($/boe)	69.89	75.47	70.52	56.10
Operating netback ($/boe)				
Petroleum and natural gas revenue	69.89	75.47	70.52	56.10
Royalties	10.82	15.41	13.39	9.60
Operating costs	19.08	16.70	11.31	11.65
Transportation costs	3.16	3.38	3.02	3.70
Operating netback	36.83	39.98	42.79	31.14

Production Estimates

The following table discloses, by product type, the total volume of production estimated by McDaniel for the year ending December 31, 2015 in the estimates of future net revenue from Proved and from Probable Reserves disclosed under *"Petroleum and Natural Gas Reserves"*.

Proved	Heavy Oil (bbl/d)	Gas (Mcf/d)	NGL (bbl/d)	Total (boe/d)
Alberta				
Atlee Buffalo	522.5	538.9	-	612.3
Heathdale	-	-	-	-
Jenner	304.7	142.2	-	328.4
Sylvan Lake	-	23.3	-	3.9
Wainwright	-	-	-	-
British Columbia				
Trutch	-	109.9	2.7	21.1
Total	**827.1**	**814.2**	**2.7**	**965.5**

Proved Plus Probable	Heavy Oil (bbl/d)	Gas (Mcf/d)	NGL (bbl/d)	Total (boe/d)
Alberta				
Atlee Buffalo	584.7	598.1	-	684.3
Heathdale	-	-	-	-
Jenner	319.5	148.2	-	344.2
Sylvan Lake	-	23.3	-	3.9
Wainwright	-	-	-	-
British Columbia				
Trutch	-	111.8	2.7	21.4
Total	**904.1**	**881.6**	**2.7**	**1053.7**

Developed and Undeveloped Lands

The following table summarizes, by province, Hemisphere's developed and undeveloped landholdings as at December 31, 2014:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	**Gross**	**Net**
Alberta						
Atlee Buffalo	800	704	6,560	6,488	**7,360**	**7,192**
Buffalo Lake	-	-	1,280	1,280	**1,280**	**1,280**
Heathdale	-	-	1,920	1,920	**1,920**	**1,920**
Jenner	6,960	4,714	21,400	20,936	**28,360**	**25,650**
Sylvan Lake	1,920	288	-	-	**1,920**	**288**
Wainwright	640	440	-	-	**640**	**440**
British Columbia						
Trutch	3,885	1,170	31,727	20,355	**35,612**	**21,525**
Total	**14,205**	**7,316**	**62,887**	**50,979**	**77,092**	**58,295**

The following table summarizes Hemisphere's unproven lands for which the Company expects its rights to explore, develop and exploit are scheduled to expire in 2015, if not continued:

	Acreage	
Location	Gross	Net
Atlee Buffalo	2,720	2,624
Buffalo Lake	1,280	1,280
Jenner	3,520	3,520

Forward Contracts

As at December 31, 2014, Hemisphere does not have any hedging or marketing arrangements that could materially impact the Company's realized sales price that have not been disclosed as financial instruments in its financial statements.

Abandonment and Reclamation Costs

The Company did not incur abandonment costs in 2014. Hemisphere estimates well abandonment costs by area for wells with assigned reserves. Such costs are included in the McDaniel Report as deductions in arriving at future net revenue. The Company expects to incur such costs for 46.9 net wells under the Proved category and 51.3 net wells under the Proved plus Probable category. The expected total abandonment costs included in the McDaniel Report (forecast pricing) under the total Proved Reserves category is $1,949,900 undiscounted ($416,000 discounted at 10%), of which no costs are estimated to be incurred during the next three years.

	Total Proved (M$)	**Total Proved Plus Probable (M$)**
2015	-	-
2016	-	-
2017	-	-
2018	-	-
2019	-	-
Remainder	1,950	2,296
Total for all years undiscounted	1,950	2,296
Total for all years discounted at 10% per year	**416**	**353**

The Company incurred $nil in reclamation costs during 2014.

As at December 31, 2014, the Company had $156,977 in various reclamation bonds and deposits held by the British Columbia Ministry of Energy, Mines and Natural Gas, and the BC Oil and Gas Commission for its properties. Of this amount, $51,442 was recorded in prepaid expenses for current commitments and $105,535 was recorded in reclamation deposits as non-current assets.

Tax Horizon

The Company was not required to pay income taxes during the year ended December 31, 2014, and has continued to build its tax pools to over $47 million with additional capital expenditures and acquisitions. Based on corporate projections, Hemisphere's net income for 2015 will be offset by the tax pools and no tax is expected to be incurred for 2015. The Company estimates that it will not be required to pay income taxes until after 2016.

Costs Incurred

The following table summarizes Hemisphere's property acquisition costs, exploration costs and development costs for the year ended December 31, 2014:

	Property Acquisition Costs			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
Total	**634,739**	**Nil**	**2,058,905**	**18,625,751**

DIVIDENDS

Hemisphere has not declared or paid any dividends since its incorporation. The future payments of dividends will depend on the earnings and financial condition of the Company and such other factors as the Board of Directors of the Company consider appropriate. See "*Risk Factors – Dividends*".

SHARE CAPITAL

Common Shares

Hemisphere has an unlimited number of common shares authorized. As of the date hereof, there are 75,803,498 common shares issued and outstanding. Holders of Hemisphere's common shares are entitled to notice of meetings and one vote per share at meetings of the Company's shareholders, to dividends if, as and when declared by the Board of Directors, and upon liquidation, dissolution or winding-up, to receive the Company's remaining property.

Stock Options

The Company has a stock option plan in place and is authorized to grant stock options to officers, directors, employees and consultants whereby the aggregate number of shares reserved for issuance may not exceed 10% of the issued shares at the time of grant and 5% of the issued shares to each optionee. Stock options are non-transferable, and have a five year term or a maximum 10 year term as regulated by the TSX-V for Tier 1 issuers. Stock options terminate not later than 90 days upon termination of employment/contract and one year in the case of retirement/death/disability. The grant price may not be less than the last closing price of the Company's shares and not less than $0.10.

As of the date hereof, the Company had 6,860,000 stock options outstanding.

Warrants

As of the date hereof, the Company did not have any warrants outstanding.

MARKET FOR SECURITIES

The common shares of the Company are listed for trading on the TSX-V under the symbol "HME".

Common Share Trading

	Price Range		
	High	Low	Average Trading Volume
2014			
January	0.69	0.49	126,800
February	0.85	0.65	135,500
March	0.81	0.67	71,600
April	0.83	0.67	89,300
May	0.78	0.67	167,000
June	0.79	0.67	138,800
July	0.79	0.65	204,100
August	0.72	0.64	178,900
September	0.75	0.63	106,400
October	0.66	0.48	88,400
November	0.55	0.47	54,700
December	0.50	0.31	108,800
2015			
January	0.40	0.23	132,700
February	0.43	0.26	114,900
March	0.40	0.32	52,100
April 1 to 20	0.36	0.31	44,031

PRIOR SALES

The following table sets forth, for each class of securities of the Company that is outstanding but not listed or quoted on a marketplace, the price at which securities of the class have been issued during the fiscal year ended December 31, 2014 and the number of securities of the class issued at that price and the date on which the securities were issued.

Date	Type of Securities	Number of Securities	Exercise Price	Expiry Date
January 6, 2014	Stock Options	685,000(1)	$0.55	January 6, 2019
September 29, 2014	Stock Options	785,000	$0.65	September 29, 2019
October 7, 2014	Stock Options	200,000	$0.61	October 7, 2019

Note:

(1) 25,000 of the 685,000 stock options granted on January 6, 2014 were exercised on June 4, 2014.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the knowledge of the directors and executive officers of Hemisphere, none of the securities of Hemisphere are held in escrow or are subject to a contractual restriction on transfer as at the date hereof.

DIRECTORS AND OFFICERS

The names, municipalities of residence, any offices held with Hemisphere, the period served as a director and principal occupations of the Company's directors and officers are set out below:

Name and Municipality of Residence	Position with Hemisphere	Director or Officer Since	Principal Occupation During the Past Five Years
Don Simmons, P. Geol.(1)(3) Vancouver, British Columbia, Canada	President and Chief Executive Officer Director	February 2008 May 2008	Previously Vice President Exploration of the Company from October 2007. Formerly, a Geologist at Sebring Energy Inc., Encana Corporation and Alberta Energy Company.
Charles O'Sullivan, B.Sc.(2)(3) Vancouver, British Columbia, Canada	Chairman Director	2000 1978	Geophysicist and Mining Executive. Chairman of Northern Continental Resources Inc. from 1986 to 2009.
Frank Borowicz, QC, CA (Hon)(2)(3)(4) Surrey, British Columbia, Canada	Director	July 2005	Retired. Partner of Davis LLP until 2011, President of Pigasus Consulting Services Ltd. since 2004, and Governor of the Vancouver Board of Trade since 2007.
Bruce McIntyre, P.Geol.(1)(2)(4) Calgary, Alberta, Canada	Director	July 2008	Most recently Executive Director of New Zealand Energy Corp. until June 2014 and previously President from April 2011 to July 2012. From 2007 to 2011, an independent consultant and President of Wexford Energy Ltd., a private company that provides consulting services for the development and operation of producing natural gas companies (private and public).
Gregg Vernon, P. Eng.(1)(4) Bogota, Cundinamarca, Colombia	Director	August 2006	Currently President of Bochica Oil & Gas Inc. Previously Interim President and Chief Executive Officer of Petrodorado Energy Ltd. from October 2013 to February 2015. Prior thereto, Interim Chief Operating Officer of Petro Magdalena Energy Corp. (formerly Alange Energy Corp.) from January, 2011 to its sale in July 2012. From October 2007 to September 2009 Chairman of Prospero Hydrocarbons Ltd., until sold to Alange Energy Corp.
Richard Wyman, B.Sc., MBA(1)(4) Calgary, Alberta, Canada	Director	October 2014	Currently, President of Northern Cross (Yukon) Ltd., a private oil and gas company, since 2010. From 2004 to 2010, Vice President and Senior Oil and Gas Analyst with Canaccord Genuity.

Ian Duncan, P. Eng. Vancouver, British Columbia, Canada	Chief Operating Officer	May 2011	Appointed Chief Operating Officer in September 2014. Previously Vice President, Engineering since May 2011 and an engineer with Hemisphere since January 2011. Prior thereto, an engineer at Solaris MCI and Talisman Energy Inc.
Dorlyn Evancic, CGA Port Coquitlam, British Columbia, Canada	Chief Financial Officer	July 2007	Previously Chief Financial Officer of Northern Continental Resources Inc. from July 2007 to November 2009. . From December 2010 to November 2011, Chief Financial Officer of Guyana Frontier Mining Corp.
Andrew Arthur, P. Geol. Delta, British Columbia, Canada	Vice President, Exploration	July 2012	A consultant for Hemisphere from January 2012 to July 2012. From December 2008 to January 2012, Technical Lead Oil Business Unit for Enerplus Corporation.
Ashley Ramsden-Wood, P.Eng. Vancouver, British Columbia, Canada	Vice President, Engineering	September 2014	A consulting engineer for Hemisphere from June 2012 to September 2014. From 2005 to 2011, an engineer with NAL Resources.

Notes:
1. *(1) Member of the Reserves Committee. Bruce McIntyre is the Chairman of the Reserves Committee.*
2. *(2) Member of the Compensation/Nominating Committee. Charles O'Sullivan is Chairman of the Compensation/Nominating Committee.*
3. *(3) Member of the Corporate Governance Committee. Frank Borowicz is Chairman of the Corporate Governance Committee.*
4. *(4) Member of the Audit Committee. Bruce McIntyre is Chairman of the Audit Committee.*

As at the date hereof, the directors and officers of the Company, as a group, owned directly or indirectly 5,231,826 common shares or approximately 7% (12% on a fully diluted basis) of the issued and outstanding common shares.

Cease Trade Orders

Other than noted below, no current director or officer of Hemisphere has, within the last ten years prior to the date of hereof, been a director, chief executive officer or chief financial officer of any issuer (including Hemisphere) that:

(a) while the person was acting in the capacity as director, chief executive officer or chief financial officer, was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation, that was in effect for a period of more than 30 consecutive days; or

(b) was subject to an order that resulted, after the director, executive officer ceased to be a director, chief executive officer or chief financial officer of an issuer, in the issuer being the subject of a cease trade or similar order or an order that denied the relevant issuer access to any exemption under securities legislation, for a period of more than 30 consecutive days, which resulted from an event that occurred while that person was acting as a director, chief executive officer or chief financial officer of the issuer.

Mr. Evancic was a director and officer of Gemco Minerals Inc., which had a cease trade order issued in August 2007 by the British Columbia Securities Commission for revisions required in its technical report pursuant to National Instrument 43-101 – *Standard of Disclosure for Mineral Projects*. The company fully complied with the British Columbia Securities Commission requirements and revocation of the cease trade order was issued in March 2008.

Bankruptcies

No current director, officer, or shareholder holding a significant number of securities to materially affect the control of Hemisphere has, within the last ten years prior to the date of this document, been a director or officer of any company (including Hemisphere) that, while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement for compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

In addition, no current director, officer or shareholder holding a significant number of securities to materially affect the control of Hemisphere has, within the last ten years prior to the date of this document, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become 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, officer or shareholder.

Penalties or Sanctions

No current director, officer, or shareholder holding a significant number of securities to materially affect the control of Hemisphere has been subject to: (i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (ii) 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.

Conflicts of Interest

Directors and officers of the Company may, from time to time, be involved with the business and operations of other oil and natural gas issuers, in which case a conflict may arise. See "*Risk Factors*".

Circumstances may arise where members of the Company’s Board of Directors serve as directors or officers of corporations which are in competition to Hemisphere’s interests. No assurances can be given that opportunities identified by such members will be provided.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that the Company is or was a party to, or that any of its property is or was subject of, during the last completed fiscal year, nor are any such legal proceedings known to the Company to be contemplated that involves a claim for damages, exclusive of interest and costs, exceeding 10% of the current assets of the Company.

During the fiscal year ended December 31, 2014, there were: (i) no penalties or sanctions imposed against the Company or by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision, and (iii) no settlement agreements the Company entered into with a court relating to a securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors or executive officers of the Company, any shareholder who beneficially owns, or controls or directs, directly or indirectly, more than 10% of the outstanding common shares of the Company or any known associate or affiliate of such persons in any transactions within the three most recently completed fiscal years of the Company or during the current fiscal year which has materially affected, or would reasonably be expected to materially affect, the Company.

TRANSFER AGENT AND REGISTRAR

The Company's transfer agent and registrar is Computershare Investor Services Inc. located at 3rd floor, 510 Burrard Street, Vancouver, British Columbia V6C 3B9.

INTEREST OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under NI 51-102 by the Company during, or related to, its most recently completed financial year other than McDaniel, the Company's independent engineering evaluator, and Smythe Ratcliffe LLP, the Company's independent auditors.

Smythe Ratcliffe LLP has confirmed that they are independent with respect to the Company within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of British Columbia.

None of the designated professionals of McDaniel have any registered or beneficial interests, direct or indirect, in any of Hemisphere's securities or other property or of Hemisphere's associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Company has not entered into any material contracts within the most recently completed fiscal year or before the most recently completed fiscal year and which are still in effect, other than:

- The Credit Facility, as outlined in *Description of the Company – History of the Company*;
- An Advance Notice Policy, as outlined in *Description of the Company – History of the Company*; and
- A Shareholder Rights Plan between Hemisphere and Computershare Investor Services Inc., executed as of March 9, 2010. The Shareholder Rights Plan was first approved by shareholders at the Company's Annual General and Special Meeting of Shareholders on August 17, 2010. The continued operation of the Shareholder Rights Plan was most recently approved by the shareholders at the Company's Annual General and Special Meeting of shareholders on June 6, 2014.

AUDIT COMMITTEE INFORMATION

Charter

The Company's Audit Committee is governed by an Audit Committee Charter, the text of which is attached as Appendix "C" of this AIF.

Composition

The Company's Audit Committee consists of four directors: Bruce McIntyre (Chairman), Frank Borowicz, Gregg Vernon and Richard Wyman. As defined in Multilateral Instrument 52-110 - *Audit Committees* ("MI 52-110"), Bruce McIntyre, Frank Borowicz, Gregg Vernon, and Richard Wyman are deemed "independent".

A member of the Audit Committee is "independent", if the member has no direct or indirect material relationship with the Company. A material relationship means a relationship which could, in the view of the Company's Board of Directors, reasonably interfere with the exercise of the member's independent judgment.

Relevant Education and Experience

MI 52-110 provides that a member of the Audit Committee is considered to be "financially literate" if he has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexities of the issues that can reasonably be expected to be raised by the Company.

All of the members of the Company's Audit Committee are considered to be "financially literate", as that term is defined in MI 52-110.

Bruce McIntyre, P.Geol., Chairman

Mr. McIntyre has over 35 years of oil and gas experience and a proven track record of finding quality oil and gas reserves. Mr. McIntyre was most recently Executive Director of New Zealand Energy Corp. until June 2014 and previously, President from April 2011 to July 2012. Prior thereto, Mr. McIntyre was President and Chief Executive Officer of Sebring Energy Inc., a private Alberta-based exploration and production company that was sold in July 2007. He has also held various other management positions including President CEO and co-founder of Sommer Energy Ltd., President and CEO of TriQuest Energy Corp., President and Chief Executive Officer of BXL Energy Ltd. and Exploration Manager for Gascan Resources Ltd. Mr. McIntyre is a member of the American Association of Petroleum Geologists, has a Professional Geologist designation with the Association of Professional Engineers and Geoscientists of Alberta and an Honorary Member of the Canadian Society of Petroleum Geologists (Past President 2002). Mr. McIntyre holds a Bachelor of Science Degree in Geology (Honours) from Carleton University and an Advanced Executive Certificate in General Management from Queen's University.

Frank Borowicz, QC, CA (Hon)

Mr. Borowicz has over 35 years of experience in corporate governance and regulatory compliance. He is a retired partner of the international law firm Davis LLP and is a Governor of the Vancouver Board of Trade. He served as Chairman of the BC Industry Training Authority and is an independent director of several public and private companies. Educated at Harvard, Dalhousie and Loyola, Mr. Borowicz is a member of the Institute of Corporate Directors, is a Queen's Counsel, and an honorary member of the Institute of Chartered Accountants.

Gregg Vernon, P.Eng.

Mr. Vernon is a designated professional engineer with over 35 years of international oil and gas industry experience, including managing and administrating major projects in China, Eastern Canada and South America. He is currently the President of Bochica Oil & Gas Inc., a private oil company in Colombia. Most recently he was interim President and Chief Executive Officer of Petrodorado Energy Ltd. from October 2013 to February 2015. Prior thereto, Mr. Vernon was the interim Chief Operating Officer of PetroMagdalena Energy Corp. (formerly Alange Energy Corp.), a Canadian-based international oil and gas exploration and production company until its sale in 2012. In October of 2007, he was a founder and Chairman of Prospero Hydrocarbons Inc., a private Canadian based international oil and gas exploration company focused on Colombia. He is one of the founders of Petro Andina Resources Ltd., a Canadian company with operations in South America. He is a University of Alberta graduate with his degree in Engineering and is a member of the Society of Petroleum Engineers.

Richard Wyman, B.Sc., MBA

With over 30 years' experience, Mr. Wyman began his career as a reservoir engineer with Esso Resources Canada Ltd. in Calgary prior to becoming a corporate finance associate with Wood Gundy in London, England. He returned to Canada and became an analyst in the corporate finance and treasury department of Gulf Canada Limited in Calgary and Toronto, and then an oil and gas equities research analyst with Peters & Co. Ltd. Following his tenure at Peters & Co., Mr. Wyman became a founding shareholder and Director of Smart Pipeline Services Ltd. and Northern Cross (Yukon) Ltd. He returned to a capital market role as Vice President and Senior Oil and Gas Analyst with Canaccord Genuity under their rebranding process in 2004. In 2010, Mr. Wyman returned to the oil and gas industry as President and a Director of Northern Cross (Yukon) Ltd, an emerging junior oil and gas, exploration and development company with assets located in Yukon. He holds a Bachelor of Applied Science degree in Chemical Engineering (Hons) from Queen's University in 1978 and a Masters of Business Administration from the International Management Institute at the University of Geneva in 1985.

External Auditors

The Company's external auditor is Smythe Ratcliffe LLP located at Suite 700, 355 Burrard Street, Vancouver, British Columbia V6C 2G8.

The fees paid by the Company to its external auditor in each of the last two fiscal years are as follows:

Fiscal Year Ending	Audit Fees(1)	Audit Related Fees(2)	Tax Fees(3)	All Other Fees(4)
December 31, 2014	50,500	26,920	Nil	Nil
December 31, 2013	44,370	27,540	6,120	Nil

Notes:

(1) *"Audit Fees" include fees necessary to perform the annual audit and quarterly reviews of the Company's financial statements. Audit Fees include fees for review of tax provisions and for accounting consultations on matters reflected in the financial statements. Audit Fees also include audit or other attest services required by legislation or regulation such as comfort letters, consents, reviews of securities filings and statutory audits.*

(2) *"Audit Related Fees" include services that are traditionally performed by the auditor. These audit related services include employee benefit audits, due diligence assistance, accounting consultations on proposed transactions, internal control reviews, consultations on conversion to International Financial Reporting Standards and audit or attest services not required by legislation or regulation.*

(3) *"Tax Fees" include fees for all tax services other than those included in "Audit Fees" and "Audit Related Fees". This category includes fees for tax compliance, tax planning and tax advice. Tax planning and tax advice include assistance with tax audits and appeals, tax advice related to mergers and acquisitions and requests for rulings or technical advice from tax authorities.*

(4) *"All Other Fees" include all other non-audit services.*

EXEMPTION

The Company is relying upon the exemption in Section 6.1 of MI 52-110 as TSX Venture Issuer.

ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR at www.sedar.com or Hemisphere's website at www.hemisphereenergy.ca. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans is contained in the Company's Information Circular for its most recent annual meeting of shareholders. Additional financial information is contained in the Company's audited annual financial statements and related Management's Discussion and Analysis for the year ended December 31, 2014.

Additional copies of this AIF, and any financial statements which have been issued by the Company, are available on the Company's website at www.hemisphereenergy.ca, upon request by mail at Suite 2000, 1055 West Hastings Street, Vancouver, British Columbia V6E 2E9, by email at info@hemisphereenergy.ca, by phone at (604) 685-9255, or by fax at (604) 685-9676.

APPENDIX "A"

FORM 51-101F2
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

March 2, 2015

Hemisphere Energy Corporation
2000, 1055 West Hastings Street
Vancouver, British Columbia
V6E 2E9

Attention: The Board of Directors of Hemisphere Energy Corporation

Re: **Form 51-101F2**
Report on Reserves Data by an Independent Qualified Reserves Evaluator
of Hemisphere Energy Corporation (the "Company")

To the Board of Directors of Hemisphere Energy Corporation (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us, for the year ended December 31, 2014, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management:

Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate) Audited	Evaluated	Reviewed	Total
March 2, 2015	Canada	-	62,478.8	-	62,478.8

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

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 judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

(Signed) *"P.A. Welch"*
P.A. Welch, P. Eng.
President & Managing Director

Calgary, Alberta
March 2, 2015

APPENDIX "B"

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

Management of Hemisphere Energy Corporation (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as December 31, 2014, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

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

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;
(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

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

(a) the content and filing with securities regulatory authorities of 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 evaluator 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.

s/s "Don Simmons"
Don Simmons
President & Chief Executive Officer

s/s "Dorlyn Evancic"
Dorlyn Evancic
Chief Financial Officer

s/s "Bruce McIntyre"
Bruce McIntyre
Director & Chairman of the Reserves Committee

s/s "Richard Wyman"
Richard Wyman
Director & Member of the Reserves Committee

April 21, 2015

APPENDIX "C"

AUDIT COMMITTEE CHARTER

Purpose

The Audit Committee of Hemisphere Energy Corporation ("Hemisphere") assists the Board of Directors in the oversight of its integrity in financial reporting as outlined in National Instrument 52-110 *Audit Committees* ("NI 52-110").

Composition

The Audit Committee consists of no less than three directors, each of whom is "financially literate" and "independent" as defined under NI 52-110, and is annually appointed by the Board of Directors. The Chair of the Audit Committee is appointed by the Board of Directors at the same time as the member appointment.

Mandate

- Assisting the Board of Directors in fulfilling their oversight responsibilities with respect to the review of financial statements and other relevant public disclosures, compliance with legal and regulatory requirements relating to financial reporting, the external auditors' qualifications and independence, and the performance of the internal audit function and the external auditors.
- Meeting quarterly to review and approve the quarterly financial statements and management's discussion and analysis for recommendation to the Board of Directors.
- Meeting annually to review and approve the audited annual financial statements and management's discussion and analysis for recommendation to the Board of Directors.
- Annually reviewing the performance of the external auditors.
- Nominating the external auditors for recommendation to the Hemisphere shareholders at the annual general meeting of the shareholders.
- Advising the Board of Directors on the remuneration of the external auditors based on the time required to complete the audit and preparation of the audited annual financial statements, and the difficulty of the audit and performance of the standard auditing procedures under generally accepted auditing standards and Generally Accepted Accounting Principles of Canada.

External Auditors

Hemisphere's external auditors are the independent representatives of the shareholders, yet are also accountable to the Board of Directors and the Audit Committee. The external auditors complete their audit procedures and reviews with professional independence, free from any undue interference from management or directors. The Audit Committee directs and ensures that the management fully co-operates with the external auditors in the course of carrying out their professional duties. The Audit Committee will have access to direct communications with the external auditors, if required.

The external auditors are prohibited from providing any non-audit services to Hemisphere, without the written consent of the Audit Committee unless such non-audit services are *De Minimus* Non-Audit Services as outlined in section 2.4 of NI 52-110. In determining whether the external auditors will be granted permission to provide non-audit services, the Audit Committee is to consider that the benefits to Hemisphere from the provision of such services, outweighs the risk of any compromise to or loss of the independence of the external auditors in carrying out their auditing mandate.

Notwithstanding the above non-audit services, the external auditors are prohibited at all times from carrying out any of the following services, while they are appointed the external auditors of Hemisphere:

(a) acting as an agent of Hemisphere for the sale of all or substantially all of the undertaking of Hemisphere; and

(b) performing any non-audit consulting work for any director or senior officer of Hemisphere in their personal capacity, but not as a director, officer or insider of any other entity not associated or related to Hemisphere.

The Audit Committee has the power to terminate the services of the external auditors, with or without the approval of the Board of Directors, acting reasonably.

Internal Controls

The Board of Directors will appoint a person who is responsible for implementing internal controls and performing the role as the internal auditor ensuring such controls are adequate and effective.

Continuous Disclosure Requirements

The Board of Directors will appoint a person who is responsible for ensuring that Hemisphere's continuous reporting requirements are met and in compliance with applicable regulatory requirements.

Annual Review

The Corporate Governance Committee annually reviews the Audit Committee Charter and recommends any amendments to the Board of Directors for approval.