Twin Butte Energy Ltd.

**ANNUAL INFORMATION FORM**

for the year ended December 31, 2013

**March 21, 2014**

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## ABBREVIATIONS

| Crude Oil and Natural Gas Liquids | | Natural Gas | |
|---|---|---|---|
| bbl | one barrel | Mcf | one thousand cubic feet |
| bbl | barrels | MMcf | one million cubic feet |
| bbl/d | barrels per day | Bcf | one billion cubic feet |
| Mbbl | thousand barrels | | |
| BOE | barrels of oil equivalent of natural gas on the basis of 1 BOE for 6 Mcf of natural gas (unless otherwise indicated) | Mcf/d | one thousand cubic feet per day |
| MBOE | one thousand barrels of oil equivalent | MMcf/d | one million cubic feet per day |
| MMBOE | one million barrels of oil equivalent | GJ | gigajoule |
| BOE/d | barrels of oil equivalent per day | GJs/d | gigajoules per day |
| NGL | natural gas liquids | Btu | British thermal unit |
| stb | standard stock tank barrel | MMbtu | million British thermal units |

**BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of six Mcf to one 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. This conversion factor is an industry accepted norm and is not based on either energy content or current prices.**

**Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion ratio at 6:1 may be misleading as an indication of value.**

### Other

| | |
|---|---|
| AECO | EnCana Corp.'s natural gas storage facility located at Suffield, Alberta |
| API | American Petroleum Institute |
| °API | an indication of the specific gravity of crude oil measured on the API gravity scale |
| $m^3$ | cubic metres |
| $000's | thousands of dollars |
| WTI | West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade |

## CONVERSIONS

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

| To Convert From | To | Multiply By |
|---|---|---|
| Mcf | thousand cubic metres ("$10^3m^3$") | 0.0282 |
| thousand cubic metres | Mcf | 35.494 |
| bbl | cubic metres ("$m^3$") | 0.159 |
| cubic metres | bbl | 6.290 |
| feet | metres | 0.305 |
| metres | feet | 3.281 |
| miles | kilometres | 1.609 |
| kilometres | miles | 0.621 |
| acres | hectares | 0.405 |
| hectares | acres | 2.471 |

## CERTAIN DEFINITIONS

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

"**ABCA**" means the *Business Corporations Act* (Alberta), together with any amendments thereto and all regulations promulgated thereunder;

"**Avalon**" means Avalon Exploration Ltd., a corporation which was incorporated pursuant to the ABCA and which was amalgamated with Twin Butte following the Avalon Acquisition;

"**Avalon Acquisition**" means Twin Butte's acquisition of all of the outstanding securities of Avalon completed on August 29, 2012 pursuant to a plan of arrangement under the ABCA as more particularly described under "General Development of the Business – Three Year History";

"**Black Shire**" means Black Shire Energy Inc., a corporation which was incorporated pursuant to the ABCA and which was amalgamated with Twin Butte Acquisition Ltd., a former wholly-owned subsidiary of the Corporation, following the Black Shire Acquisition;

"**Black Shire Acquisition**" means Twin Butte's acquisition of all of the outstanding class "A" common shares of Black Shire completed on November 5, 2013 pursuant to a plan of arrangement under the ABCA as more particularly described under "General Development of the Business – Three Year History";

"**Board of Directors**" means the board of directors of the Corporation;

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

"**Common Shares**" means the common shares in the capital of the Corporation as currently constituted;

"**Convertible Debentures**" means the $85 million aggregate principal amount of 6.25% convertible unsecured subordinated debentures of Twin Butte, due December 31, 2018;

"**Emerge**" means Emerge Oil & Gas Inc., a corporation which was incorporated pursuant to the ABCA and which was amalgamated with Twin Butte following the Emerge Acquisition;

"**Emerge Acquisition**" means Twin Butte's acquisition of all of the outstanding common shares of Emerge completed on January 9, 2012 pursuant to a plan of arrangement under the ABCA as more particularly described under "General Development of the Business – Three Year History";

"**Gross**" means:

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

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

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

"**McDaniel**" means McDaniel & Associates Consultants Ltd., independent petroleum consultants, Calgary, Alberta;

"**McDaniel Report**" means the February 28, 2014 report prepared by McDaniel, evaluating the crude oil, natural gas and NGL reserves of Twin Butte, as at December 31, 2013, in accordance with the standards contained in the COGE Handbook and the reserves definitions set out by the Canadian Securities Administrators in NI 51-101 and the COGE Handbook;

"**Net**" means:

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

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

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

"**NI 51-101**" means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* adopted by the Canadian Securities Administrators;

"**Subscription Receipt Offering**" means the issuance by Twin Butte on October 31, 2013 of 35,898,000 subscription receipts at a price of $1.95 per subscription receipt for gross proceeds of approximately $70 million;

"**Tax Act**" means the *Income Tax Act* (Canada), R.S.C. 1985, c. 1., as amended, including the regulations promulgated thereunder;

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

"**Twin Butte**" or the "**Corporation**" means Twin Butte Energy Ltd., a corporation incorporated pursuant to the ABCA;

"**Waseca**" means Waseca Energy Inc., a corporation which was incorporated pursuant to the ABCA and which was amalgamated with Twin Butte following the Waseca Acquisition; and

"**Waseca Acquisition**" means Twin Butte's acquisition of all of the outstanding securities of Waseca completed on November 1, 2012 pursuant to a plan of arrangement under the ABCA as more particularly described under "General Development of the Business – Three Year History".

## CONVENTIONS

Certain terms used herein are defined under the heading "Glossary of Terms".

Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars.

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

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2013.

## READER ADVISORY REGARDING FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, the timing, entitlement and amount of future dividend payments, financial and business prospects and financial outlook, reserve and production estimates, drilling and re-completion plans, timing of drilling, re-completion and tie-in of wells, productive capacity of wells and productive capacity of wells and capital expenditures and the timing thereof, the effect of government announcements, proposals and legislation, plans regarding hedging, expected or anticipated production rates, timing of expected production increases, weighting of production between different commodities, expected commodity prices, exchange rates, production expenses, transportations costs and other costs and expenses, maintenance of productive capacity and capital expenditures and methods of financing thereof, may be forward-looking statements. 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, 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 the Corporation's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

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

Readers are cautioned that the foregoing list of factors is not exhaustive. Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

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

## CORPORATE STRUCTURE

### Name, Address and Incorporation

Twin Butte Energy Ltd.

| | |
|---|---|
| Head Office:<br>Suite 410, 396 – 11th Avenue S.W.<br>Calgary, Alberta T2R 0C5 | Registered Office:<br>Suite 2400, 525 – 8th Avenue S.W.<br>Calgary, Alberta T2P 1G1 |

Twin Butte was formed upon the amalgamation under the ABCA on May 31, 1997 of Altarex Corp. and Altarex Inc. to form "Altarex Corp.". On June 27, 1997, the newly formed Altarex Corp. filed Articles of Amendment to add in certain other provisions to allow the company to hold meetings of shareholders at any place within Canada or the United States. On November 21, 2000, Altarex Corp. filed Articles of Amendment to consolidate its common shares on the basis of one post-consolidated common share for each four pre-consolidated common shares.

On February 3, 2004, Articles of Arrangement were filed with respect to a plan of arrangement under section 193 of the ABCA among the Corporation, the Corporation's securityholders, Altarex Medical Corp. ("**Altarex Medical**"), a wholly-owned subsidiary of the Corporation, and Nova Bancorp Investments Ltd. (the "**Arrangement**") resulting in the following: (a) the reorganization of the Corporation's share capital to create new classes of non-voting common shares (the "**Non-Voting Shares**") and voting common shares; (b) the change of the name of the Corporation to "Twin Butte Energy Ltd."; and (c) the deletion of the class of common shares (the "**Pre-Arrangement Shares**") and the re-designation of the new class of voting common shares as the Common Shares. Pursuant to the Arrangement: (a) all of the Corporation's biotechnology assets were transferred, together with all associated contractual obligations and liabilities to Altarex Medical, in consideration for 40,000,000 common shares of Altarex Medical (the "**Altarex Medical Shares**") and the subscription by the Corporation for 12,746,935 additional Altarex Medical Shares for $5,045,000 in cash; (b) the issuance to Nova Bancorp Investments Ltd. of $4,770,985 principal amount of 10% convertible demand notes of Twin Butte, convertible into Non-Voting Shares of Twin Butte at a ratio of 2,583 Non-Voting Shares per $1,000 of principal (the "**Convertible Notes**"); (c) the cancellation of all outstanding stock options and warrants of the Corporation; and (d) the exchange of the Pre-Arrangement Shares on the following basis: (i) shareholders who held more than 1,000 Pre-Arrangement Shares received one Common Share of Twin Butte and ten Altarex Medical Shares for every ten Pre-Arrangement Shares held; (ii) shareholders who held 151 to 1,000 Pre-Arrangement Shares received an aggregate payment equal to $0.05 and one Altarex Medical Share for each Pre-Arrangement Share held; and (iii) shareholders who held 150 Pre-Arrangement Shares or less, received an aggregate cash payment equal to $0.55 for each Pre-Arrangement Share held.

On June 7, 2006, Twin Butte filed Articles of Amendment under the ABCA to convert the Non-Voting Shares of the Corporation into Common Shares. On May 28, 2007, Twin Butte filed Articles of Amendment under the ABCA to consolidate its then outstanding Common Shares on the basis of one post-consolidated Common Share for each five pre-consolidated Common Shares.

On February 8, 2008, following the completion of the acquisition of all of the outstanding common shares of E4 Energy Inc., Twin Butte amalgamated with E4 Energy Inc. to form "Twin Butte Energy Ltd.".

On July 13, 2009, following the completion of the acquisition of all of the outstanding common shares of Can-Able Energy Ltd., Twin Butte amalgamated with Can-Able Energy Ltd. to form "Twin Butte Energy Ltd.".

On October 14, 2009, following the completion of the acquisition of all of the outstanding common shares of Buffalo Resources Corp., Twin Butte amalgamated with Buffalo Resources Corp. to form "Twin Butte Energy Ltd.".

On January 9, 2012, following the completion of the Emerge Acquisition, Twin Butte amalgamated with Emerge to form "Twin Butte Energy Ltd.".

On August 29, 2012, following the completion of the Avalon Acquisition, Twin Butte amalgamated with Avalon to form "Twin Butte Energy Ltd.".

On November 1, 2012, following the completion of the Waseca Acquisition, Twin Butte amalgamated with Waseca to form "Twin Butte Energy Ltd.".

On May 15, 2013, Twin Butte amended its articles to change the rights, privileges, restrictions and conditions in respect of the Common Shares, to enable Twin Butte to issue Common Shares as payment of all or any portion of dividends declared on the Common Shares for those shareholders of Twin Butte who elect to receive stock dividends instead of cash dividends.

On November 5, 2013, following the completion of the Black Shire Acquisition, Twin Butte amalgamated with Twin Butte Acquisition Ltd. to form "Twin Butte Energy Ltd.".

Unless otherwise stated, disclosure in this Annual Information Form of the share capital of Twin Butte is presented after giving effect to the foregoing amendments to the Articles of Twin Butte.

## GENERAL DEVELOPMENT OF THE BUSINESS

### Three Year History

The following is a summary of the significant events in the development of the Corporation's business over the last three completed financial years.

#### *Year Ended December 31, 2011*

During the year ended December 31, 2011, the majority of Twin Butte's operations and capital expenditures were focused in its core operating area of Frog Lake in the Eastern Plains of Alberta where the Corporation drilled 108 gross (67.2 net) wells during the year at a 100% success rate. In addition to the Frog Lake area, the Corporation tested a number of new plays including at Earlie in west central Alberta and Esther in the Eastern Plains. During the year ended December 31, 2011, Twin Butte continued to focus on oil-based opportunities and drilled an aggregate of 125 gross (80.9 net) wells and exited the year with production of approximately 7,700 BOE/d (64% NGLs and oil).

#### *Year Ended December 31, 2012*

On January 9, 2012, Twin Butte acquired all of the issued and outstanding common shares of Emerge pursuant to the Emerge Acquisition in consideration of the issuance of approximately 54.1 million Common Shares to the former shareholders of Emerge. Concurrent with completion of the Emerge Acquisition, the borrowing base under Twin Butte's demand credit facility with a syndicate of financial institutions was increased from $128 million to $205 million and Twin Butte assumed Emerge's bank debt of approximately $58.3 million under its increased credit facility. Emerge had two core property areas: Lloydminster, Saskatchewan and Alberta (heavy oil) and Provost, East-Central Alberta (light and medium oil). Following the completion of the Emerge Acquisition, the Board of Directors of Twin Butte approved an initial monthly dividend of $0.015 per issued and outstanding Common Share. See "Dividends".

On April 1, 2012, Twin Butte completed the acquisition of approximately 320 bbl/d at Swimming, located to the southwest of Frog Lake for approximately $14.1 million and which added over 20 100% working interest sections of undeveloped land.

On August 29, 2012, Twin Butte acquired all of the issued and outstanding securities of Avalon pursuant to the Avalon Acquisition in consideration of the issuance of approximately 24.6 million Common Shares to the former security holders of Avalon. Concurrent with completion of the Avalon Acquisition, the borrowing base under Twin Butte's demand credit facility with a syndicate of financial institutions was increased from $205 million to $240 million. The Avalon Acquisition effectively doubled Twin Butte's net undeveloped land position in the Lloydminster heavy oil region, and added approximately 1,900 BOE/d of production.

On October 10, 2012, Twin Butte acquired a property at Wildmere in the Corporation's Lloydminster heavy oil area for approximately $20 million. At the time of the acquisition, the property was producing approximately 450 BOE/d, of which 80% was conventional heavy oil.

On November 1, 2012, Twin Butte paid approximately $134 million (including the assumption of approximately $10.8 million of positive working capital and after accounting for estimated transaction costs) and issued approximately 30.2 million Common Shares to acquire all of the outstanding securities of Waseca pursuant to the Waseca Acquisition. Waseca's 3,200 BOE/d of production was from heavy oil properties located within 100 kilometres of the City of Lloydminster, Alberta. The Waseca Acquisition materially increased the size and scope of heavy oil lands and opportunities for Twin Butte. The cash portion of the Waseca Acquisition was funded through available funds under the credit facility. Following the completion of the Waseca Acquisition, Twin Butte increased its monthly dividend from $0.015 to $0.016 per issued and outstanding Common Share. See "Dividends". In connection with the completion of the Waseca Acquisition, Twin Butte's credit facility with a syndicate of financial institutions was increased from $240 million to $280 million and was converted from a demand to a committed facility.

During the year ended December 31, 2012, the majority of Twin Butte's operations and capital expenditures were focused in its core operating area of the Lloydminster heavy oil region of Alberta/Saskatchewan where the Corporation drilled 95 gross (77.2 net) wells during the year at a 96% success rate. During the year ended December 31, 2012, all of Twin Butte's efforts were focused on oil-based opportunities in this region. Twin Butte exited the year with production of approximately 19,200 BOE/d (87% NGLs and oil).

***Year Ended December 31, 2013***

In January and July 2013, Twin Butte announced that certain of its wells at its Primate Property in western Saskatchewan had experienced reservoir and production issues. As a result, production from the Primate Property decreased from approximately 3,210 bbls/d as at December 31, 2012 to approximately 575 bbls/d as at December 31, 2013.

In June 2013, Twin Butte completed construction of a cleaning/staging facility at Lashburn, Saskatchewan which has led to increased rail car shipments now exceeding 30% of Twin Butte's heavy oil volumes.

On October 31, 2013, Twin Butte completed the Subscription Receipt Offering for gross proceeds of approximately $70 million, which proceeds were held in escrow pending completion of the Black Shire Acquisition. On November 5, 2013, in accordance with their terms, each subscription receipt was exchanged for one Common Share upon the closing of the Black Shire Acquisition and the net proceeds from the sale of the subscription receipts were released from escrow to Twin Butte to fund part of the cash consideration for the Black Shire Acquisition.

On November 5, 2013, Twin Butte completed the Black Shire Acquisition. Black Shire was a private company with a focused asset base in the greater Provost area of Alberta, producing approximately 7,000 BOE/d (93 percent medium gravity oil) at the time of the acquisition. The greater Provost area is directly adjacent to Twin Butte's core Lloydminster heavy oil area. Pursuant to the Black Shire Acquisition, Twin Butte acquired all of the issued and outstanding class "A" common shares of Black Shire for total net consideration of approximately $357 million, including the assumption of approximately $85.4 million of net debt at closing. Twin Butte issued approximately 54 million Common Shares and paid an aggregate of approximately $155 million to acquire all of the issued and outstanding class "A" common shares of Black Shire, subject to certain withholdings. The cash consideration for the Black Shire Acquisition was partially funded through the Subscription Receipt Offering. In connection with the completion of the Black Shire Acquisition, the borrowing base of Twin Butte's syndicated credit facility (the "**Credit Facility**") was increased from $280 million to $400 million, consisting of a revolving line of credit of $375 million and an operating line of credit of $25 million with a revolving period currently expiring on April 29, 2014, extendible annually at the request of Twin Butte for a further 364 days, subject to approval of the lenders and repayable one year after the expiry of the revolving period. The borrowing base of the Credit Facility is determined based on, among other things, Twin Butte's current reserve report, results of operations, current and forecasted commodity prices and the current economic environment. The Credit Facility is subject to semi-annual review by the lenders and is secured by a $750 million demand debenture in respect of all of Twin Butte's assets and a general assignment of book debts in respect of all accounts of Twin Butte.

On December 13, 2013, Twin Butte completed the offering of $85 million aggregate principal amount of Convertible Debentures at a price of $1,000 per Convertible Debenture. The net proceeds of the offering were used to reduce bank indebtedness providing Twin Butte with additional financial flexibility through the diversification of its indebtedness and interest rate certainty on a portion of its core debt. The Convertible Debentures bear interest at a rate of 6.25% per annum, payable semi-annually in arrears on the last day of June and December in each year commencing on June 30, 2014, and will mature on December 31, 2018 (the "**Maturity Date**"). The Convertible Debentures are convertible at the holder's option into

Common Shares at any time prior to the earlier of the Maturity Date and the date fixed for redemption at a conversion price of $3.05 per Common Share (the "**Conversion Price**"), subject to adjustment in certain circumstances. The Convertible Debentures are not redeemable before December 31, 2016. On or after December 31**,** 2016 but prior to December 31, 2017, the Convertible Debentures will be redeemable at Twin Butte's option at par plus accrued and unpaid interest, provided that the weighted average trading price of the Common Shares on the TSX during the 20 consecutive trading days ending on the fifth trading day preceding the date on which notice of redemption is given is not less than 125% of the Conversion Price. On or after December 31, 2017 but prior to the Maturity Date, the Convertible Debentures will be redeemable at Twin Butte's option at par plus accrued and unpaid interest. Twin Butte shall provide not more than 60 nor less than 30 days' prior notice of redemption. The Convertible Debentures are listed for trading on the TSX under the symbol "TBE.DB". See "Market for Securities – Trading Price and Volume of Convertible Debentures".

During the year ended December 31, 2013, the majority of Twin Butte's operations and capital expenditures were focused in the Lloydminster heavy oil region of Alberta/Saskatchewan, a core operating area of the Corporation, where the Corporation drilled 95 gross (93.3 net) wells (of the Corporation's total 97 gross (95.3 net) wells) during the year at a 93% success rate. During the year ended December 31, 2013, all of Twin Butte's efforts were focused on oil-based opportunities in this region. Twin Butte exited the year with production of approximately 23,000 BOE/d (92% NGLs and oil).

**Significant Acquisitions**

The Corporation completed the following significant acquisition during its most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations*.

On November 5, 2013, Twin Butte completed the Black Shire Acquisition pursuant to which Twin Butte acquired all of the issued and outstanding class "A" common shares of Black Shire for total net consideration of approximately $357 million, including the assumption of approximately $85.4 million of net debt at closing. Twin Butte issued approximately 54 million Common Shares and paid an aggregate of approximately $155 million to acquire all of the issued and outstanding class "A" common shares of Black Shire, subject to certain withholdings. The cash consideration for the Black Shire Acquisition was partially funded through the Subscription Receipt Offering. Further information in respect of the Black Shire Acquisition is contained in the Business Acquisition Report of Twin Butte dated November 8, 2013 filed on SEDAR at www.sedar.com.

## DESCRIPTION OF THE BUSINESS

**General**

Twin Butte is a Calgary, Alberta based dividend paying, value oriented intermediate oil and gas producer with a significant and growing scalable and repeatable drilling inventory focused on large original oil in-place conventional medium and heavy oil exploitation. With a stable decline production base, Twin Butte believes it is well positioned to live within cash flow while providing shareholders with a sustainable dividend and moderate per share production growth potential over the long term. Twin Butte is committed to continually enhance its asset quality while focusing on the sustainability of its dividend.

**Business Plan and Corporate Strategy**

Twin Butte's 2014 capital program is $145 to $150 million, which will be split between the Provost medium oil plays acquired in 2013 and the Lloydminster heavy oil fairway. Twin Butte expects to drill approximately 45 gross horizontal medium oil wells in the Provost region and approximately 30 gross vertical heavy oil wells and 30 gross horizontal heavy oil wells in the Lloydminster region. In addition, Twin Butte expects to complete an extensive workover and recompletion program focused in the Provost region and the Lloydminster region.

Twin Butte is currently producing approximately 7,200 bbl/d of medium gravity crude in the Provost region and has identified over 150 wells in the region to be drilled.

The size and scope of Twin Butte's heavy oil operations and opportunities at greater Lloydminster is significant, currently accounting for approximately 12,600 bbl/d. Twin Butte as a significant operator in the area believes it will have a competitive advantage when it comes to procurement of equipment and services as well as acquisition opportunities. Core properties in the area are Frog Lake, Wildmere, Tangleflags and Celtic. With the extensive drill ready management identifiable inventory of over 500 net locations, these properties will see extensive heavy oil development drilling programs in 2014 and beyond. As well, the evaluation and possible pilot testing of enhanced oil recovery through thermal, waterflood and polymer applications have been identified.

Twin Butte believes that reinvesting approximately 65% to 70% of its cash flow will provide targeted production per share growth rates of two to four percent. This combined with the annualized dividend of $0.192 per share, or $66 million in aggregate (before giving effect to the dividend reinvestment plans), is anticipated to provide attractive total returns to shareholders by providing both sustainable income (via dividends) and moderate internal production growth. It is anticipated that the all-in payout ratio of under 100% will leave some excess cash for continued balance sheet strengthening.

The Corporation's near term strategy is very much focused on improving the predictability and sustainability of its business model through organic growth. With an anticipated combined stable, predictable base decline of approximately 28% and forecast capital efficiency of under $20,000 per producing BOE per day, Twin Butte believes its cash flow and dividend will be sustainable for the foreseeable future. The strong capital efficiency is driven by the Corporation's extensive low risk, high rate of return medium and heavy oil drilling inventory and its ability to high grade this large inventory of drilling locations.

In addition, the Corporation will focus on acquiring stable, low decline assets with reasonable netbacks. With a significant supply of oil and gas assets on the market, Twin Butte believes this portion of the strategy could prove very successful especially considering the experience and background of Twin Butte management. As a larger, dividend paying company, Twin Butte believes it is well positioned to compete for such acquisitions.

Twin Butte will continue to pursue non-core asset sales to focus operations and improve the quality of its asset base, maintain cost control and further strengthen the balance sheet. The Corporation's large undeveloped land base of approximately 328,000 net acres and its approximately 120 net natural gas drilling locations are also anticipated to provide swap/farm out and other rationalization or monetization opportunities.

**Specialized Skill and Knowledge**

Twin Butte believes that its management team has all of the key components to successfully implement is business plan: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; extensive experience in oil and gas exploration and development in Western Canada; and an entrepreneurial spirit that allows Twin Butte to effectively identify, evaluate and execute on value-added initiatives. See "Directors and Executive Officers".

**Competitive Conditions**

The oil and natural gas industry is intensely competitive in all its phases. Twin Butte 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. Twin Butte's competitors include resource companies which have greater financial resources, staff and facilities than those of Twin Butte. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Twin Butte 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.

**Cyclical Nature of Business**

The Corporation's business is generally cyclical. The exploration and development of oil and natural gas reserves is dependent on access to areas where drilling is to be conducted. Seasonal weather variation, including freeze-up and break-up, will affect access in certain circumstances.

**Employees**

As at December 31, 2013, Twin Butte had 85 full-time employees and six consultants. Five of the consultants and 56 of the full-time employees were located at Twin Butte's office in Calgary and 29 of the full-time employees and one consultant were located in the field.

## DESCRIPTION OF PRINCIPAL PROPERTIES

The following is a description of Twin Butte's principal oil and natural gas properties as at December 31, 2013. Unless otherwise specified, gross, net acres, well count and production information are as at December 31, 2013.

Twin Butte's production is derived from the following five regions: the Provost region, the Lloydminster region (comprised of the Frog Lake field, the Saskatchewan - South field, the Saskatchewan - Central field, the Saskatchewan - North field and the Alberta - Other Heavy field), the Plains region, the West Central Alberta region and the Pincher Creek region, descriptions of which are set forth below.

### Provost Region

The Provost medium oil region is located along the eastern edge of Alberta between Township 36-43 and Range 1-6 W4M. Twin Butte acquired these lands in November 2013 pursuant to the Black Shire Acquisition. Production from this region as at December 31, 2013 was approximately 7,000 BOE/d of which approximately 93% is medium gravity oil in the 21 to 25 ºAPI range. The main producing zones in the region are the Cummings and Dina zones at a depth of approximately 600 to 700 metres. Twin Butte drilled two horizontal wells in this region in 2013 subsequent to acquiring the lands and plans to drill up to 45 horizontal wells in the region during 2014.

### Lloydminster Region

The Lloydminster heavy oil region is centered around the City of Lloydminster on the Alberta/Saskatchewan border. It encompasses an area from Township 36 in the south to Township 57 in the north and from Range 17W3 to Range 8W4, east to west. This is the major operating area for Twin Butte accounting for approximately 78% of its production volumes in 2013 (approximately 13,736 BOE/d) and approximately 84% of revenues. This region's production is predominantly heavy oil in the 12º to 16º API range that comes from a variety of zones including the Colony, Upper McLaren, Sparky, General Petroleum, Rex and Waseca at depths of 500 to 700 metres. Twin Butte has approximately 189,800 net undeveloped acres in this region. Of the 97 gross (93.3 net) wells drilled in 2013 by Twin Butte, 95 were drilled in this region and it is anticipated that approximately 50% of the wells to be drilled by Twin Butte in 2014 will be drilled in this region. Twin Butte's capital program for 2014 includes the drilling of approximately 30 gross vertical heavy oil wells and 30 gross horizontal heavy oil wells, as well as an extensive workover and recompletion program focused in the Lloydminster heavy oil region. Production in the Lloydminster region for 2013 was split approximately 65/35 between Saskatchewan and Alberta. Some of the key areas in Saskatchewan are Ear Lake and Primate in the south, Silverdale, Furness and Lashburn in the central area, and Celtic and Tangleflags in the north. In Alberta, Frog Lake, Wildmere and Swimming are the main contributors to Twin Butte's production.

The Corporation's significant producing fields in the Lloydminster heavy oil region are the Frog Lake field, the Saskatchewan - South field, the Saskatchewan - Central field, the Saskatchewan - North field and the Alberta - Other Heavy field, descriptions of which are set forth below.

#### *Frog Lake Field*

The Frog Lake field is located approximately 75 kilometres northwest of Lloydminster with lands on the Frog Lake First Nations lands and on Crown land just to the south of the First Nations lands. Twin Butte's working interests in the Frog Lake field range from 11% to 100%. The Corporation drilled four gross (2.6 net) horizontal wells at Frog Lake in 2013. The Frog Lake field produced approximately 2,539 BOE/d in 2013, representing approximately 14% of Twin Butte's production volumes for the year. This production consisted of 100% heavy oil. The main zones in the field are 400 to 550 metres deep and include the McLaren, Sparky, GP and Rex formations. Oil production from the field is currently trucked to third party processing facilities where it is sold.

***Saskatchewan - South Field***

The main producing areas in this field are Ear Lake, Freemont and Primate which are located in Townships 37-38, Ranges 24-28 W3M. Twin Butte drilled 15 wells in this field in 2013, all at a 100% working interest, and at year end had a total of 33 producing wells. 2013 production from the field averaged 2,250 BOE/d with current production at approximately 1,325 BOE/d. The Primate area encountered production losses in January and July 2013, reducing production to approximately 575 BOE/d at December 31, 2013. No additional development is currently planned at Primate.

***Saskatchewan - Central Field***

The main producing areas in this field are Silverdale, Furness and Lashburn which are located in Townships 48-49, Ranges 24-27 W3M. Twin Butte drilled 12 wells in this field in 2013. Production from the Silverdale, Furness and Lashburn areas averaged approximately 2,123 BOE/d in 2013 or approximately 75% of the Saskatchewan - Central field volumes.

***Saskatchewan - North Field***

The main producing areas in this field are Celtic, Mervin and Tangleflags and they are located in Townships 49-52, Ranges 19-28 W3M. Twin Butte drilled 13 wells in this field in 2013. Production from the Celtic, Mervin and Tangleflags areas averaged 3,825 BOE/d in 2013 or effectively 100% of the production from the Saskatchewan - North field.

***Alberta – Other Heavy Field***

The main producing areas in this field are Swimming, Wildmere and Lloydminster. Swimming is located in Township 53, Ranges 6-7 W4M and Wildmere is at Township 47, Ranges 6-7 W4M. During 2013, Twin Butte drilled nine wells in the Swimming area and 30 wells in the Wildmere area. Twin Butte plans to drill up to 18 horizontal wells in the Wildmere area in 2014. Production from the Swimming, Wildmere and Lloydminster areas averaged approximately 2,230 BOE/d in 2013, or 96% of this field's total average production of 2,314 BOE/d in 2013.

**Plains Region**

The Plains region is on the eastern half of Alberta running from east of Calgary to southeast of Edmonton, and includes operational areas such as Bruce, Battlebend and Jenner. Production from this region was approximately 908 BOE/d in 2013, consisting of approximately 50% oil and liquids and 50% natural gas. This region is known for both oil and natural gas and producing zones in this region include the Viking, Lloydminster, Glauconite and Pekisko with depths ranging from 700 to 1,000 metres.

Production in the region generally goes to a combination of Twin Butte operated facilities and third party operated facilities. Twin Butte has approximately 41,700 net undeveloped acres in this region.

Twin Butte did not drill any wells in this region during 2013 but plans to drill at least two wells in this region in 2014.

**West Central Alberta Region**

The West Central Alberta region is 125 kilometres northwest of Edmonton and stretches to northwestern Alberta and northeastern British Columbia, including operations in strike areas of Whitecourt and Thunder. Production from this region was approximately 1,013 BOE/d in 2013, consisting of approximately 14% oil and liquids and 86% natural gas. This region is known for both oil and natural gas and producing zones in this region include the Viking, upper and lower Manville, Nordegg and Banff formations with depths ranging from 800 to 1,800 metres.

Production in the region goes to a combination of Twin Butte operated facilities and third party operated facilities. Twin Butte has approximately 33,000 net undeveloped acres in this region.

**Pincher Creek Region**

The Pincher Creek region is 20 kilometres southeast of Pincher Creek, Alberta. Production from this region was approximately 451 BOE/d in 2013, consisting of approximately 73% natural gas. This region was initially developed in the 1960's and has produced more than 500 Bcf of gas to date with more than 50 Bcf remaining. The gas in this region is from the Turner Valley group zone and is approximately 10% sour with H2S, which requires special processing capabilities at the Shell Canada Waterton gas plant.

Twin Butte has a 100% interest in the Pincher Creek Unit which covers 41 sections of land and a 60% interest in one non-unit well. During 2012, production was shut-in from July to October while maintenance was conducted at the Shell Canada Waterton gas plant.

The Corporation did not drill any wells in this region in 2013 and is not planning to drill any wells in this region in 2014.

Twin Butte has approximately 16,800 net undeveloped acres in this region.

## STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated March 21, 2014. The effective date of the Statement is December 31, 2013. The reserves data is based upon an evaluation and review prepared by McDaniel with a preparation date of February 28, 2014.

**Disclosure of Reserves Data**

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation and review by McDaniel with an effective date of December 31, 2013 contained in the McDaniel Report. The Reserves Data summarizes the crude oil, NGL and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs. McDaniel evaluated approximately 90% of the total proved plus probable future net revenue discounted at 10%. McDaniel evaluated in the McDaniel Report approximately 74% of the assigned total proved plus probable reserves and reviewed the internal evaluation completed by Twin Butte on the remaining portion, which primarily included certain non-core natural gas assets in Alberta and British Columbia. The McDaniel Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and the COGE Handbook. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which Twin Butte believes is important to the readers of this information. The Corporation engaged McDaniel to provide an evaluation and review of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

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

The Report on Reserves Data by McDaniel & Associates Consultants Ltd. in accordance with Form 51-101F2 and the Report of Twin Butte Management and Directors on Oil and Gas Disclosure in accordance with Form 51-101F3 are attached to this Annual Information Form as Schedules "A" and "B", respectively.

**It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of the Corporation's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.**

*Reserves Data (Forecast Prices and Costs)*

**SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS**

| | Light and Medium Oil | | Heavy Oil | | Natural Gas | | Natural Gas Liquids | |
|---|---|---|---|---|---|---|---|---|
| **Reserves Category** | **Gross (Mbbl)** | **Net (Mbbl)** | **Gross (Mbbl)** | **Net (Mbbl)** | **Gross (MMcf)** | **Net (MMcf)** | **Gross (Mbbl)** | **Net (Mbbl)** |
| Proved Developed Producing | 2,656.1 | 2,471.9 | 14,254.3 | 12,353.4 | 41,310.8 | 34,510.7 | 1,788.6 | 1,209.5 |
| Proved Developed Non-Producing | 47.7 | 44.7 | 1,862.8 | 1,585.0 | 7,086.1 | 5,733.8 | 392.9 | 264.8 |
| Proved Undeveloped | 485.3 | 420.0 | 7,634.0 | 6,615.0 | 6,996.4 | 5,871.6 | 336.2 | 235.3 |
| Total Proved | 3,189.1 | 2,936.5 | 23,751.1 | 20,553.5 | 55,393.4 | 46,116.1 | 2,517.7 | 1,709.7 |
| Total Probable | 1,840.4 | 1,622.8 | 22,642.3 | 19,146.2 | 24,623.2 | 20,209.7 | 949.9 | 653.3 |
| Total Proved Plus Probable | 5,029.5 | 4,559.3 | 46,393.4 | 39,699.7 | 80,016.6 | 66,325.8 | 3,467.6 | 2,363.0 |

| | Net Present Values OF Future Net Revenue ($000's) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Before Income Taxes Discounted At (%/year) | | | | | After Income Taxes Discounted at (%/year) | | | | | Unit Value Before Income Tax Discounted at 10%/year |
| **Reserves Category** | **0** | **5** | **10** | **15** | **20** | **0** | **5** | **10** | **15** | **20** | **($/boe)** |
| Proved Developed Producing | 616,510 | 535,769 | 480,101 | 438,884 | 406,780 | 616,510 | 535,769 | 480,101 | 438,884 | 406,780 | 18.75 |
| Proved Developed Non-Producing | 88,406 | 62,623 | 50,690 | 43,254 | 37,895 | 83,602 | 58,201 | 46,601 | 39,458 | 34,359 | 14.55 |
| Proved Undeveloped | 191,329 | 152,155 | 123,598 | 101,859 | 84,846 | 149,248 | 114,804 | 90,175 | 71,734 | 57,519 | 12.85 |
| Total Proved | 896,244 | 750,547 | 654,389 | 583,997 | 529,520 | 849,360 | 708,775 | 616,877 | 550,077 | 498,657 | 16.90 |
| Total Probable | 832,023 | 615,460 | 488,465 | 401,541 | 337,809 | 639,536 | 464,839 | 363,190 | 294,351 | 244,391 | 16.53 |
| Total Proved Plus Probable | 1,728,268 | 1,366,007 | 1,142,854 | 985,538 | 867,329 | 1,488,895 | 1,173,613 | 980,067 | 844,428 | 743,048 | 16.74 |

**TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS
($000's)**

| Reserves Category | Revenue | Royalties | Operating Costs | Development Costs | Well Abandonment Costs | Future Net Revenue Before Income Taxes | Future Income Taxes | Future Net Revenue After Future Income Taxes |
|---|---|---|---|---|---|---|---|---|
| Proved | 2,698,425 | 391,586 | 1,189,207 | 167,227 | 54,160 | 896,244 | 46,885 | 849,360 |
| Proved Plus Probable | 4,841,580 | 730,711 | 1,974,832 | 340,421 | 67,347 | 1,728,268 | 239,373 | 1,488,895 |

**FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS**

| Reserves Category | Production Group | Future Net Revenue Before Income Taxes (discounted at 10%/year) ($000's) | Unit Value Before Income Taxes (discounted at 10%/year) ($/Mcf) ($/bbl) |
|---|---|---|---|
| Proved Reserves | Light and Medium Crude Oil (including solution gas and other by-products) | 75,112 | 25.69 |
| | Heavy Oil (including solution gas and other by-products) | 523,808 | 25.49 |
| | Natural Gas (including by-products but excluding solution gas from oil wells) | 55,469 | 1.29 |
| | **Total** | 654,389 | 19.84 |
| Proved Plus Probable | Light and Medium Crude Oil (including solution gas and other by-products) | 114,590 | 25.23 |
| | Heavy Oil (including solution gas and other by-products) | 945,771 | 23.82 |
| | Natural Gas (including by-products but excluding solution gas from oil wells) | 82,493 | 1.34 |
| | **Total** | 1,142,854 | 18.78 |

**Notes to Reserves Data Tables:**

(1) Columns may not add due to rounding.

(2) The crude oil, natural gas liquids and natural gas reserve estimates presented in this Annual Information Form are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below:

***Reserve Categories***

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

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, which are generally accepted as being reasonable and shall be disclosed.

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

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

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

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

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

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

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

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

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

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

***Levels of Certainty for Reported Reserves***

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

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

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

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

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

(3) "**forecast prices and costs**" are those:

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

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

The forecast summary table under the "Pricing Assumptions" below identifies benchmark reference prices that apply to Twin Butte.

(4) "**future income taxes**" estimated:

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

(d) without deducting estimated future costs that are not deductible in computing taxable income;

(e) taking into account estimated tax credits and allowances; and

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

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

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

(g) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

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

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

(j) provide improved recovery systems.

(7) "**exploration well**" means a well that is not a development well, a service well or a stratigraphic test well.

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

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

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

(m) dry hole contributions and bottom hole contributions;

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

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

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

### *Pricing Assumptions*

**SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS**
**FORECAST PRICES AND COSTS**

| Year | WTI Cushing Oklahoma ($US/bbl) | Light Sweet Crude Oil at Edmonton 40° API ($Cdn/bbl) | Medium Bow River Crude Oil 21° API ($Cdn/bbl) | Hardisty Heavy 12° API ($Cdn/bbl) | Natural Gas AECO-C Spot ($Cdn/ MMBtu) | Natural Gas Liquids Edmonton Cond ($Cdn/bbl) | Natural Gas Liquids Edmonton Propane ($Cdn/bbl) | Natural Gas Liquids Edmonton Butane ($Cdn/bbl) | Inflation Rates [1] %/Year | Exchange Rate [2] ($US/$Cdn) |
|---|---|---|---|---|---|---|---|---|---|---|
| Forecast | | | | | | | | | | |
| 2014 | 95.00 | 95.00 | 77.90 | 67.50 | 4.00 | 102.50 | 50.20 | 76.60 | 2.0 | 0.95 |
| 2015 | 95.00 | 96.50 | 81.10 | 70.40 | 4.25 | 101.60 | 50.50 | 77.80 | 2.0 | 0.95 |
| 2016 | 95.00 | 97.50 | 81.90 | 71.20 | 4.55 | 100.60 | 50.60 | 78.60 | 2.0 | 0.95 |
| 2017 | 95.00 | 98.00 | 82.30 | 71.50 | 4.75 | 101.20 | 51.30 | 79.00 | 2.0 | 0.95 |
| 2018 | 95.30 | 98.30 | 82.60 | 71.80 | 5.00 | 101.50 | 52.00 | 79.20 | 2.0 | 0.95 |
| 2019 | 96.60 | 99.60 | 83.70 | 72.70 | 5.25 | 102.90 | 53.20 | 80.30 | 2.0 | 0.95 |
| 2020 | 98.50 | 101.60 | 85.30 | 74.20 | 5.35 | 105.00 | 54.10 | 81.90 | 2.0 | 0.95 |
| 2021 | 100.50 | 103.60 | 87.00 | 75.60 | 5.45 | 107.00 | 55.20 | 83.50 | 2.0 | 0.95 |
| 2022 | 102.50 | 105.70 | 88.80 | 77.20 | 5.55 | 109.20 | 56.30 | 85.20 | 2.0 | 0.95 |
| 2023 | 104.60 | 107.90 | 90.60 | 78.80 | 5.65 | 111.50 | 57.40 | 87.00 | 2.0 | 0.95 |
| 2024 | 106.70 | 110.00 | 92.40 | 80.30 | 5.75 | 113.70 | 58.50 | 88.60 | 2.0 | 0.95 |
| Thereafter | +2%/yr | +2%/yr | +2%/yr | +2%/yr | +2%/yr | +2%/yr | +2%/yr | +2%/yr | 2.0 | 0.95 |

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

### *Reconciliation of Changes in Reserves*

The following table sets out the reconciliation of Twin Butte's gross reserves based on forecast prices and costs by principal product type:

| | Light and Medium Oil | | | Heavy Oil | | | Associated and Non-Associated Gas | | | Natural Gas Liquids | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Factors** | **Gross Proved (Mbbl)** | **Gross Probable (Mbbl)** | **Gross Proved Plus Probable (Mbbl)** | **Gross Proved (Mbbl)** | **Gross Probable (Mbbl)** | **Gross Proved Plus Probable (Mbbl)** | **Gross Proved (MMcf)** | **Gross Probable (MMcf)** | **Gross Proved Plus Probable (MMcf)** | **Gross Proved (Mbbl)** | **Gross Probable (Mbbl)** | **Gross Proved Plus Probable (Mbbl)** |
| **December 31, 2012** | 1,232.5 | 733.9 | 1,966.4 | 17,525.0 | 17,830.5 | 35,355.5 | 62,140.2 | 29,431.0 | 91,571.2 | 2,561.1 | 1,047.1 | 3,608.2 |
| Discoveries, Extensions and Improved Recovery | 93.8 | 60.3 | 154.1 | 4,123.5 | 1,651.8 | 5,775.3 | 757.8 | 158.9 | 916.7 | 4 | 2 | 6 |
| Technical Revisions | 283.4 | 112.8 | 396.2 | 64.5 | (2,714.9) | (2,650.4) | (426.7) | (2,640.5) | (3,067.2) | 112.9 | (49.2) | 63.7 |
| Acquisitions and Dispositions | 1,793.1 | 933.5 | 2,726.6 | 7,405.4 | 5,875.0 | 13,280.4 | (2,489.1) | (2,326.0) | (4,815.1) | (87.3) | (50.0) | (137.3) |
| Economic Factors | - | - | - | - | - | - | - | - | - | - | - | - |
| Production | (213.7) | - | (213.7) | (5,367.3) | - | (5,367.3) | (4,589.0) | - | (4,589.0) | (73.0) | - | (73.9) |
| **December 31, 2013** | 3,189.1 | 1,840.4 | 5,029.5 | 23,751.1 | 22,642.3 | 46,393.4 | 55,393.4 | 24,623.2 | 80,016.6 | 2,517.7 | 949.9 | 3,467.6 |

Notes:
(1) The Corporation has no unconventional reserves (bitumen, synthetic crude oil, natural gas from coal, etc.).
(2) Numbers may not add due to rounding.

## Additional Information Relating to Reserves Data

### *Undeveloped Reserves*

#### *Proved Undeveloped Reserves*

The following table sets forth, for each product type, the volumes of proved undeveloped reserves that were first attributed in each of the three most recent financial years and, in the aggregate, before that time.

| | Light and Medium Oil (Mbbl) | | Heavy Oil (Mbbl) | | Natural Gas (MMcf) | | Natural Gas Liquids (Mbbl) | | BOE (MBOE) | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **First Attributed** | **Cumulative at Year End** | **First Attributed** | **Cumulative at Year End** | **First Attributed** | **Cumulative at Year End** | **First Attributed** | **Cumulative at Year End** | **First Attributed** | **Cumulative at Year End** |
| Prior thereto | 69.8 | 337.7 | 1,832.5 | 4,657.5 | 1,132.9 | 8,771.6 | 4.5 | 177.1 | 2,095.6 | 6,634.3 |
| 2011 | 30.1 | 303.8 | 475.8 | 3,474.0 | 480.0 | 8,387.8 | 2.6 | 192.5 | 588.4 | 5,368.3 |
| 2012 | 218.4 | 369.3 | 2,553.8 | 6,067.3 | 182.4 | 7,427.0 | 4.7 | 344.7 | 2,807.3 | 8,019.1 |
| 2013 | - | 485.3 | 1,460.7 | 7,634.0 | 131.5 | 6,996.4 | 1.3 | 336.2 | 1,483.9 | 9,621.6 |

At year end 2013, proved undeveloped reserves were primarily attributed to drilling locations in the Lloydminster region and the Provost region.

#### *Probable Undeveloped Reserves*

The following table sets forth, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the three most recent financial years and, in the aggregate, before that time.

| | Light and Medium Crude Oil (Mbbl) | | Heavy Oil (Mbbl) | | Natural Gas (MMcf) | | Natural Gas Liquids (Mbbl) | | BOE (MBOE) | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **First Attributed** | **Cumulative at Year End** | **First Attributed** | **Cumulative at Year End** | **First Attributed** | **Cumulative at Year End** | **First Attributed** | **Cumulative at Year End** | **First Attributed** | **Cumulative at Year End** |
| Prior thereto | 20.0 | 343.5 | 1,916.3 | 5,132.5 | 1,675.8 | 17,544.2 | 19.9 | 390.8 | 2,235.6 | 8,790.8 |
| 2011 | 15.0 | 310.7 | 2,006.7 | 5,701.6 | 756.7 | 13,942.6 | 3.8 | 329.8 | 2,151.6 | 8,665.9 |
| 2012 | 277.8 | 477.7 | 5,726.9 | 10,597.1 | 53.6 | 12,091.2 | 1.8 | 507.3 | 6,015.5 | 13,597.3 |
| 2013 | - | 888.8 | 1,463.0 | 13,431.6 | 103.2 | 10,261.3 | 1.0 | 468.8 | 1,481.3 | 16,499.4 |

At year end 2013, the majority of the probable undeveloped reserves were attributed to drilling locations in the Lloydminster region and the Provost region.

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

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

### *Significant Factors or Uncertainties*

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on current production forecasts, prices and economic conditions.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

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

Other than as discussed above and the various risks and uncertainties that participants in the oil and gas industry are exposed to generally, Twin Butte is unable to identify any important economic factors or significant uncertainties that will affect any particular components of the reserves data disclosed herein. See "Risk Factors".

### *Future Development Costs*

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserve categories noted below ($000's):

| | **Undiscounted Forecast Prices and Costs ($000's)** | |
|---|---|---|
| **Year** | **Proved Reserves** | **Proved Plus Probable Reserves** |
| 2014 | 57,922 | 111,561 |
| 2015 | 57,200 | 112,653 |
| 2016 | 41,033 | 91,423 |
| 2017 | 7,859 | 16,733 |
| 2018 | 1,338 | 652 |
| Thereafter | 1,875 | 7,399 |
| **Total** | 167,227 | 340,421 |

The Corporation expects that the capital listed in the preceding table will be funded through internally generated cash flows and will not have any associated funding costs. Therefore, the capital commitments will not affect the disclosed reserves of future net revenue.

## Other Oil and Gas Information

For a description of the Corporation's important oil and gas properties, please see "Description of Principal Properties".

### *Oil and Gas Wells*

The following table sets forth the number and status of wells in which the Corporation had a working interest as at December 31, 2013.

| | **Oil Wells** | | | | **Natural Gas Wells** | | | |
|---|---|---|---|---|---|---|---|---|
| | **Producing** | | **Non-Producing** | | **Producing** | | **Non-Producing** | |
| | **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** |
| Alberta | 1,253 | 963 | 917 | 761 | 322 | 184 | 259 | 177 |
| British Columbia | 2 | 2 | 7 | 5 | 9 | 9 | 18 | 15 |
| Saskatchewan | 592 | 547 | 314 | 281 | 27 | 20 | 34 | 26 |
| Total | 1,847 | 1,512 | 1,238 | 1,047 | 358 | 213 | 311 | 218 |

Note:
(1) Numbers may not add due to rounding.

### *Properties with no Attributable Reserves*

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2013.

| | **Developed Acres** | | **Undeveloped Acres** | | **Total Acres** | |
|---|---|---|---|---|---|---|
| | **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** |
| Alberta | 295,880 | 201,307 | 217,746 | 172,854 | 513,626 | 374,161 |
| British Columbia | 11,686 | 10,015 | 6,926 | 4,113 | 18,612 | 14,129 |
| Saskatchewan | 68,792 | 67,309 | 154,996 | 151,107 | 223,788 | 218,416 |
| Total | 376,358 | 278,632 | 379,668 | 328,074 | 756,026 | 606,706 |

The Corporation expects that rights to explore, develop and/or exploit up to 92,547 net acres of its undeveloped land holdings may expire by December 31, 2014. Twin Butte plans to drill or submit applications to continue selected portions of the above acreage.

### *Additional Information Concerning Abandonment and Reclamation Costs*

The Corporation uses its best estimate of costs which are generally in line with the Alberta Energy Regulator assigned liability to estimate its abandonment and reclamation costs when available. If the Corporation does not have a historic basis of actual costs then the Alberta Energy Regulator costs are used. If representative comparisons are not readily available, an estimate is prepared based on the industry's historical costs. As at December 31, 2013, the Corporation had 3,220 net wells for which it expects to eventually incur abandonment and reclamation costs.

The total abandonment and reclamation costs in respect of proved and probable reserves using forecast prices is $54.2 million (undiscounted) and $25.1 million (discounted at 10%). One hundred percent of such amounts were deducted as abandonment and reclamation costs in estimating future net revenue of the Corporation in respect of proved and probable reserves as disclosed above.

The following table sets forth abandonment and reclamation costs deducted in the estimation of the Corporation's future net revenue:

**Forecast Prices and Costs (Total Proved) ($000's)**

| **Year** | **Abandonment and Reclamation Costs (Undiscounted)** |
|---|---|
| 2014 | - |
| 2015 | - |
| 2016 | 1,063 |
| Thereafter | 53,097 |
| Total Undiscounted | 54,160 |
| Total Discounted at 10% | 25,127 |

### *Tax Horizon*

The Corporation has no current tax expense and based on current reserve forecasts will be able to realize the benefit of the majority of the non-capital losses and remain non-taxable until the latter half of 2015. Twin Butte has estimated approximately $788 million of tax pools will be available as at December 31, 2013, which can be used to offset taxable income in future years.

***Capital Expenditures***

The following table summarizes the Corporation's property acquisition (disposition) costs, separately for proved properties and unproved properties, exploration costs and development costs for the year ended December 31, 2013:

| | **000's** |
|---|---|
| Property acquisition costs | |
| Proved properties | 370 |
| Unproved properties | - |
| Exploration costs | 6,186 |
| Development costs | 96,772 |
| Dispositions | (29,631) |
| Other | 3,479 |
| Total | 77,176 |

***Exploration and Development Activities***

The following table sets forth the gross and net exploratory and development wells in which Twin Butte participated in the year ended December 31, 2013:

| | **Exploratory Wells** | | **Development Wells** | |
|---|---|---|---|---|
| | **Gross** | **Net** | **Gross** | **Net** |
| Natural Gas | - | - | - | - |
| Oil | - | - | 87 | 85.3 |
| Service | - | - | 3 | 3.0 |
| Dry | - | - | 7 | 7.0 |
| Total | - | - | 97 | 95.3 |

***Production Estimates***

The following table sets out the volume of the Corporation's production estimated for the year ended December 31, 2014 as evaluated by McDaniel, which is reflected in the estimate of future net revenue disclosed in the tables contained under "Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data".

**FORECAST PRICES AND COSTS**

| | **Light and Medium Oil** | **Heavy Oil** | **Natural Gas** | **Natural Gas Liquids** | **TOTAL** |
|---|---|---|---|---|---|
| **Reserves Category** | **Gross (bbl/d)** | **Gross (bbl/d)** | **Gross (Mcf/d)** | **Gross (bbl/d)** | **Gross (BOE/d)** |
| **Proved** | | | | | |
| Frog Lake | - | 2,176.7 | 24.8 | - | 2,180.8 |
| Pincher Creek | - | - | 2,515.6 | 163.5 | 582.8 |
| Alberta Other Heavy | - | 2,510.0 | 673.3 | - | 2,622.2 |
| Provost | 6,555.8 | - | 2,316.6 | 65.5 | 7,007.4 |
| West Central | 50.3 | - | 4,531.7 | 95.8 | 901.4 |
| Plains | 441.1 | - | 1,624.3 | 8.8 | 720.6 |
| Saskatchewan - North | - | 2,907.7 | - | - | 2,907.7 |

| Reserves Category | Light and Medium Oil Gross (bbl/d) | Heavy Oil Gross (bbl/d) | Natural Gas Gross (Mcf/d) | Natural Gas Liquids Gross (bbl/d) | TOTAL Gross (BOE/d) |
|---|---|---|---|---|---|
| Saskatchewan - Central | - | 2,423.4 | 377.8 | - | 2,486.4 |
| Saskatchewan - South | - | 1,172.8 | - | - | 1,172.8 |
| Other Properties | 12.5 | - | 759.2 | 5.6 | 144.6 |
| Total Proved | 7,059.7 | 11,190.6 | 12,823.3 | 339.2 | 20,726.7 |
| | | | | | |
| **Proved Plus Probable** | | | | | |
| Frog Lake | - | 2,733.4 | 25.7 | - | 2,737.7 |
| Pincher Creek | - | - | 2,790.8 | 181.4 | 646.5 |
| Alberta Other Heavy | - | 3,070.7 | 706.9 | - | 3,188.5 |
| Provost | 7,250.2 | - | 2,412.4 | 69.7 | 7,722.0 |
| West Central | 52.1 | - | 5,047.7 | 104.0 | 997.4 |
| Plains | 468.1 | - | 1,711.0 | 9.0 | 762.3 |
| Saskatchewan - North | - | 3,622.3 | - | - | 3,622.3 |
| Saskatchewan - Central | - | 2,906.3 | - | - | 2,906.3 |
| Saskatchewan - South | - | 1,626.2 | - | - | 1,626.2 |
| Other Properties | 14.2 | - | 794.1 | 11.5 | 158.1 |
| Total Proved Plus Probable | 7,784.6 | 13,958.9 | 13,904.3 | 375.6 | 24,436.6 |

Note:
(1) Numbers may not add due to rounding.

The Corporation's Provost field is the only fields which accounts for 20% or more of the Corporation's estimated 2014 production in the McDaniel Report.

***Production History***

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

| | Quarter Ended 2013 | | | |
|---|---|---|---|---|
| | **December 31** | **September 30** | **June 30** | **March 31** |
| **Average Daily Production** (1) | | | | |
| Light and Medium Crude Oil (bbl/d) | 4,710 | 501 | 614 | 783 |
| Heavy Oil (bbl/d) | 13,123 | 13,541 | 13,974 | 13,890 |
| Gas (Mcf/d) | 11,634 | 12,111 | 12,665 | 13,907 |
| NGLs (bbl/d) | 188 | 202 | 150 | 263 |
| Combined (BOE/d) | 19,960 | 16,263 | 16,849 | 17,254 |
| | | | | |
| **Average Price Received** | | | | |
| Light and Medium Crude Oil ($/bbl) | 66.19 | 98.72 | 84.48 | 69.44 |
| Heavy Oil ($/bbl) | 60.28 | 87.11 | 69.22 | 48.51 |
| Gas ($/Mcf) | 3.78 | 2.64 | 3.71 | 3.50 |
| NGLs ($/bbl) | 77.50 | 78.71 | 88.51 | 78.01 |
| Combined ($/BOE) | 58.19 | 78.52 | 64.24 | 46.21 |
| | | | | |
| **Royalties Paid** | | | | |
| Light and Medium Crude Oil ($/bbl) | 8.79 | 16.34 | 12.51 | 9.56 |
| Heavy Oil ($/bbl) | 14.00 | 20.13 | 15.32 | 10.19 |
| Gas ($/Mcf) | (0.44) | (0.10) | 0.36 | 0.09 |
| NGLs ($/bbl) | 51.00 | 24.98 | (5.15) | 28.05 |
| Combined ($/BOE) | 11.50 | 17.51 | 13.39 | 9.14 |

| | Quarter Ended 2013 | | | |
|---|---|---|---|---|
| | December 31 | September 30 | June 30 | March 31 |
| **Production Costs** (2) | | | | |
| Combined ($/BOE) | 23.18 | 24.01 | 25.88 | 24.21 |
| **Resulting Netback** (3) | | | | |
| Combined ($/BOE) | 23.51 | 37.00 | 24.97 | 12.86 |

Notes:
(1) Before deduction of royalties.
(2) Operating expenses are composed of direct costs incurred to operate both oil and gas wells and include transportation costs. Operating recoveries associated with operated properties were excluded from operating costs and accounted for as a reduction to general and administrative costs.
(3) Netbacks are calculated by subtracting royalties and operating costs from revenues before hedging.

The following table indicates the Corporation's average daily production from its important fields for the year ended December 31, 2013:

| | Light and Medium Crude Oil (bbl/d) | Heavy Oil (bbl/d | Gas (Mcf/d) | NGLS (bbl/d) | BOE (BOE/d) |
|---|---|---|---|---|---|
| Frog Lake | - | 2,534 | 27 | - | 2,538 |
| Saskatchewan - South | - | 2,250 | - | - | 2,250 |
| Saskatchewan - Central | - | 2,804 | - | - | 2,804 |
| Saskatchewan - North | - | 3,825 | 25 | - | 3,829 |
| Alberta Other | - | 2,232 | 476 | 3 | 2,314 |
| Provost | 1,083 | - | 370 | 10 | 1,155 |
| Plains Alberta | 447 | - | 2,713 | 9 | 908 |
| West Central | 79 | - | 5,228 | 63 | 1,013 |
| Pincher Creek | - | - | 2,342 | 61 | 451 |
| Deep Basin | 38 | - | 1,381 | 55 | 323 |
| Total | 1,647 | 13,645 | 12,562 | 201 | 17,585 |

For the year ended December 31, 2013, 94.5% of Twin Butte's gross revenue was derived from crude oil production, 3.9% was derived from natural gas production and the remaining 1.6% was derived from NGLs.

***Forward Contracts and Marketing***

Twin Butte uses financial derivatives or fixed price contracts to manage its exposure to fluctuations in commodity prices and foreign currency exchange rates. A description of such instruments is provided in note 5 of Twin Butte's annual audited financial statements and related management's discussion and analysis for the year ended December 31, 2013, which may be found on SEDAR at www.sedar.com.

## INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada.

## Pricing and Marketing

### *Oil*

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. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional market and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale. 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. The NEB is currently undergoing a consultation process to update the regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* which received Royal Assent on June 29, 2012 (the "**Prosperity Act**"). In this transitory period, 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*".

### *Natural Gas*

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 $m^3$/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

## The North American Free Trade Agreement

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. 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 the total supply of goods of the party maintaining the restriction as compared to 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 measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply.

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

## Royalties and Incentives

### *General*

In addition to federal regulation, each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects, 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. Royalties from production on Crown lands 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 carved out of the working interest owner's interest, from time to time, 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 or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

### *Alberta*

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

Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework", which was implemented in 2010. Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36%.

Oil sands projects are also subject to Alberta's royalty regime. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma: rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1-9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher. In addition, concurrent with the implementation of The New Royalty Framework, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the new royalty regime.

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4% of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "**IETP**") has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

The Emerging Resource and Technologies Initiative will be reviewed in 2014, and the Government of Alberta has committed to providing industry with three years notice if it decides to discontinue the program.

***British Columbia***

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is classified as either "old oil" which is produced from a pool discovered before October 31, 1975, "new oil" produced from a pool discovered between October 31, 1975 and June 1, 1998, and "third-tier oil" produced from a pool discovered after June 1, 1998 or through an enhanced oil recovery ("**EOR**") scheme. The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low-productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula 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. Royalties on natural gas liquids are levied at a flat rate of 20% of the sales volume.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. It is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the freehold production tax is either a flat rate, or, at certain production levels, 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. The production tax rate for freehold natural gas liquids is a flat rate of 12.25%.

British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity natural gas wells. These include both royalty credit and royalty reduction programs, including the following:

- *Deep Well Royalty Credit Program* providing a royalty credit for natural gas wells defined in terms of a dollar amount applied against royalties, is well specific and applies to drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 1,900 metres (or 2,300 metres if spud before September 1, 2009) and if certain other criteria are met and is intended to reflect the higher drilling and completion costs. Effective on April 1, 2014, the Deep Well Royalty Credit Program will have two tiers—"tier one" and "tier two". The existing Deep Well Royalty Credit Program, as described above, will comprise tier two of the program. Tier one of the Deep Well Royalty Credit Program will apply to shallower horizontal wells with a true vertical depth less than 1,900 metres if spud after March 31, 2014;

- *Deep Re-Entry Royalty Credit Program* providing a royalty credit for deep re-entry wells with a true vertical depth to the top of pay of the re-entry well event that is greater than 2,300 metres and a re-entry date after November 30, 2003; or if the well was spud on or after January 1, 2009, with a true vertical depth to the completion point of the re-entry well event being greater than 2,300 metres;

- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 $m^3$ of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation;

- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 $m^3$ as well as a royalty credit for coalbed gas wells equal to $50,000 for wells drilled on Crown land and a tax credit equal to $30,000 for wells drilled on freehold land;

- *Marginal Royalty Reduction Program* providing a monthly royalty reduction for low productivity natural gas wells with an average daily rate of production less than 23 $m^3$ for every metre of marginal well depth in the first 12 months of production. To be eligible, wells must have been spudded after May 31, 1998 and the first month of marketable gas production must have occurred between June 2003 and August 2008. Once a well passes the initial eligibility test, a reduction is realized in each month that average daily production is less than 25,000$m^3$;

- *Ultra-Marginal Royalty Reduction Program* providing royalty reductions for low productivity, shallow natural gas wells. Vertical wells must be less than 2,500 metres and horizontal wells less than 2,300 metres to be eligible. Production in the first 12 months ending after January 2007 must be less than 17$m^3$ per metre of depth for exploratory wildcat wells and less than 11$m^3$ per metre of depth for development wells and exploratory outpost wells. The well must have been spudded or re-entered after December 31, 2005. A reduction is realized in each month that average daily production is less than 60,000$m^3$. Effective on April 1, 2014, the Ultra-Marginal Royalty Reduction Program will no longer apply to horizontal wells due to the potential for overlap with shallower horizontal wells eligible for a royalty credit under the Deep Well Royalty Credit Program; and

- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

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 comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program that provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to facilitate increased oil and gas exploration and production in under-developed areas and to extend the drilling season.

The Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation has been 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.

***Saskatchewan***

In Saskatchewan, the amount payable as a Crown royalty or a freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is divided into "types", being "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The vintage of oil, being "fourth tier oil", "third tier oil", "new oil" and "old oil", depends on the finished drilling date of a well and is applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (produced from a vertical well having a finished drilling date on or after January 1, 1994 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1994 and before October 1, 2002), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after October 1, 2002) or new oil (conventional oil that is not classified as "third tier oil" or "fourth tier oil"). Southwest designated oil uses the same definition of fourth tier oil but third tier oil is defined as conventional oil produced from a vertical well having a finished drilling date on or after February 9, 1998 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after February 9, 1998 and before October 1, 2002 and new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification as heavy oil is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, conventional oil produced from a horizontal well having a finished drilling date on or after April 1, 1991 and before October 1, 2002, or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1974 and before 1994 whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil. Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the "Production Tax Factor" ("**PTF**") applicable to that classification of oil. Currently the PTF is 6.9 for "old oil", 10.0 for "new oil" and "third tier oil" and 12.5 for "fourth tier oil". The minimum rate for freehold production tax is zero.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil and apply at a reference well production rate of 100 $m^3$ for "old oil", "new oil" and "third tier oil", and 250 $m^3$ per month for "fourth tier oil". Where average wellhead prices are below the established base prices of $100 per $m^3$ for third and fourth tier oil and $50 per $m^3$ for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as a Crown royalty or a freehold production tax in respect of natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the Saskatchewan government, the quantity produced in a given month, the type of natural gas, and the classification of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" (gas produced from gas wells) or "associated gas" (gas produced from oil wells) and royalty rates are determined according to the finished drilling date of the respective well. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of at least 3,500 $m^3$ of gas for every $m^3$ of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* with the intention to facilitate the efficient payment of freehold production taxes by industry. Two new regulations with respect to this legislation are: (i) *The Freehold Oil and Gas Production Tax Regulations, 2012* which sets out the terms and conditions under which the taxes are calculated and paid; and (ii) *The Recovered Crude Oil Tax Regulations*, 2012 which sets out the terms and conditions under which taxes on recovered crude oil that was delivered from a crude oil recovery facility on or after March 1, 2012 are to be calculated and paid.

As with conventional oil production, base prices based on a well reference rate of 250 $10^3$ $m^3$/month are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $1.35 per gigajoule for third and fourth tier gas and $0.95 per gigajoule for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas**.** The current regulatory scheme provides for **c**ertain differences with respect to the administration of "fourth tier gas" which is associated gas.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 8,000 $m^3$ for deep development vertical oil wells, 4,000 $m^3$ for non-deep exploratory vertical oil wells and 16,000 $m^3$ for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 $m^3$ for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 6,000 $m^3$ for non-deep horizontal oil wells and 16,000 $m^3$ for deep horizontal oil wells (more than 1,700 metres total vertical depth or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing for a classification of the well as a qualifying exploratory gas well and resulting in a reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 $m^3$ for horizontal gas wells and after the incentive volume is produced, the gas produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* whereby incremental production from approved waterflood projects is treated as fourth tier oil for the purposes of Crown royalty and freehold tax calculations;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing lower Crown royalty and freehold tax determinations based in part on the profitability of EOR projects during and subsequent to the payout of the EOR operations;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1% of gross revenues on EOR projects pre-payout and 20% of EOR operating income post-payout and a freehold production tax of 0% pre-payout and 8% post-payout on operating income from EOR projects; and

- *Royalty/Tax Regime for High Water-Cut Oil Wells* designed to extend the product lives and improve the recovery rates of high water-cut oil wells and granting "third tier oil" royalty/tax rates with a Saskatchewan Resource Credit of 2.5% for oil produced prior to April 2013 and 2.25% for oil produced on or after April 1, 2013 to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards, which are designed to reduce emissions resulting from the flaring and venting of associated gas (the "**Associated Natural Gas Standards**"). The Associated Natural Gas Standards were jointly developed with industry and the implementation of such standards commenced on July 1, 2012 for new wells and facilities licensed on or after such date. The new standards will apply to existing licensed wells and facilities on July 1, 2015.

**Land Tenure**

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces. 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. Private ownership of oil and natural gas also exists in such provinces 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 provinces of Alberta, British Columbia and Saskatchewan has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. On March 29, 2007, British Columbia expanded its policy of deep rights reversion 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.

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license.

**Environmental Regulation**

The oil and natural gas industry is currently subject to regulation pursuant to a variety of provincial and federal environmental legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability and the imposition of material fines and penalties.

***Federal***

Pursuant to the *Prosperity Act*, 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 in to 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.

***Alberta***

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy Regulator (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*. On March 29, 2014, the AER is expected to assume the energy related functions and responsibilities of AESRD in the areas of environment and water under the *Environmental Protection and Enhancement Act* and the *Water Act*, 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 objective behind the transformation to a single regulator is the creation of an 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.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). 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 province. It calls for the development of seven 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.

Proclaimed in force in Alberta on October 1, 2009, the *Alberta Land Stewardship Act* (the "**ALSA**") provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established under the ALSA are deemed to be legislative instruments equivalent to regulations and 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, licenses, registrations, 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.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82% of the province's oilsands resources and much of the Cold Lake oilsands area.

LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oilsands companies' tenure has been (or will be) cancelled in conservation areas and no new oilsands tenure will be issued. While new oil sands tenure will be issued in provincial recreation areas, new and existing oil sands tenure will prohibit surface access.

The next regional plan to take effect is the South Saskatchewan Regional Plan ("**SSRP**") which covers approximately 83,764 square kilometres and includes 45 % of the provincial population. The SSRP was released in draft form in 2013 and is expected to come into force on April 1, 2014.

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.

***British Columbia***

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") impacts conventional oil and gas producers, shale gas producers and other operators of oil and gas facilities in the province. 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 OGAA requires the Commission to consider these environmental objectives in deciding whether or not to authorize an oil and gas activity. In addition, although not an exclusively environmental statute, the *Petroleum and Natural Gas Act* requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. 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.

***Saskatchewan***

In May 2011, Saskatchewan passed changes to *The Oil and Gas Conservation Act* ("**SKOGCA**"), the act governing the regulation of resource development operations in the province. Although the associated Bill received Royal Assent on May 18, 2011, it was not proclaimed into force until April 1, 2012, in conjunction with the release of *The Oil and Gas Conservation Regulations, 2012* ("**OGCR**") and *The Petroleum Registry and Electronic Documents Regulations* ("**Registry Regulations**"). The aim of the amendments to the SKOGCA, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. With the enactment of the Registry Regulations and the OGCR, Saskatchewan has implemented a number of operational aspects, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural aspects including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

**Liability Management Rating Programs**

***Alberta***

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 licences 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. Some of the important changes include:

- A 25% increase to the prescribed average reclamation cost for each individual well or facility (which will increase a licensee's deemed liabilities);
- A $7,000 increase to facility abandonment cost parameters for each well equivalent (which will increase a licensee's deemed liabilities);
- A decrease in the industry average netback from a five-year to a three-year average (which will affect the calculation of a licensee's deemed assets as the reduction from five to three years means the average will be more sensitive to price changes); and
- A change to the present value and salvage factor, increasing to 1.0 for all active facilities from the current 0.75 for active wells and 0.50 for active facilities (which will increase a licensee's deemed liabilities).

These changes will be implemented over a three-year period. The first phase was implemented in May of 2013, the second phase will be implemented in May of 2014 and the final phase will be implemented in May of 2015. The changes to the LLR Program stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

***British Columbia***

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.

***Saskatchewan***

In Saskatchewan, the Ministry of Economy implements the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to post a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities.

**Climate Change Regulation**

***Federal***

The Government of Canada is a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC which represents a broad political consensus and reinforces commitments to reducing greenhouse gas ("**GHG**") emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17% reduction of GHG emissions from 2005 levels. This target is aligned with the United States target. In a report dated October 2013, the Government stated that this target represents a significant challenge in light of strong economic growth (Canada's economy is projected to be approximately 31% larger in 2020 compared to 2005 levels).

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, for application to regulated sectors on a facility-specific, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing GHG emissions and is working on regulations for other sectors. 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. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce GHG emissions.

***Alberta***

As part of Alberta's 2008 Climate Change Strategy, the province committed to taking action on three themes: (a) conserving and using energy efficiently (reducing GHG emissions); (b) greening energy production; and (c) implementing carbon and capture storage.

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate Change and Emissions Management Act* (the "**CCEMA**") enacted on December 4, 2003 and amended 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 and aims for a 50% reduction from 1990 emissions relative to GDP by 2020. The accompanying regulations include the *Specified Gas Emitters Regulation* ("**SGER**"), which imposes GHG limits, and the *Specified Gas Reporting Regulation*, which imposes GHG emissions reporting requirements. Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions.

The SGER, effective July 1, 2007, applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year, and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER. The SGER distinguishes between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity by 12% of their baseline emissions intensity for 2008 and subsequent years. Generally, the baseline for an Established Facility reflects the average of emissions intensity in 2003, 2004 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the SGER. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year and 10% of their baseline in the eighth year. The CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA provides that regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund at a rate of $15 per tonne of $CO_2$ equivalent. The funds contributed by industry to the Climate Change and Emissions Management Fund will be used to drive innovation and test and implement new technologies for greening energy production. Emissions credits can also be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta will invest $2 billion into demonstration projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

***British Columbia***

In February 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The 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 $CO_2$ equivalent. The final scheduled increase took effect on July 1, 2012. There is no plan for further rate increases or expansions at this time. 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.

In the 2012 Budget, British Columbia announced that the government would undertake a comprehensive review of the carbon tax and its impact on British Columbians. The review covered all aspects of the carbon tax, including revenue neutrality, and considered the impact on the competitiveness of British Columbia businesses such as those in the agriculture sector, and in particular, British Columbia's food producers. After the review last year, British Columbia confirmed that it will keep its revenue-neutral carbon tax, the current carbon tax rates and tax base will be maintained and revenues will continue to be returned through tax reductions.

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. It sets a province-wide target of a 33% reduction in the 2007 level of GHG emissions by 2020 and an 80% reduction by 2050. 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. The *Reporting Regulation*, implemented under the authority of the Cap and Trade Act, sets out the requirements for the reporting of the GHG emissions from facilities in British Columbia emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year beginning on January 1, 2010. Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. Recent amendments to the Cap and Trade Act repealed past requirements on public-sector organizations, including Crown corporations, to be carbon neutral by 2010, and they are now only required to produce annual carbon reduction plans and reports. Additional regulations that will further enable British Columbia to implement a cap and trade system are currently under development.

***Saskatchewan***

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. The MRGGA establishes a framework for achieving the provincial target of a 20% reduction in GHG emissions from 2006 levels by 2020. The MRGGA and related regulations have yet to be proclaimed in force.

## RISK FACTORS

**Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with the Corporation's business and the oil and natural gas business generally. If any of the following risks or other risks occur, the Corporation's business, prospects, financial condition, results of operations and cash flows could be adversely affected in a material way.**

### Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Corporation's existing reserves, and the production from them, will decline over time as the Corporation produces from such reserves. A future increase in the Corporation's reserves will depend on both the ability of the Corporation to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil and natural gas.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells as well as from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, and 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, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively 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, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation.

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 Corporation's business, financial condition, results of operations and prospects.

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event the Corporation could incur significant costs.

**Global Economic Uncertainty**

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader United States and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. While there are signs of economic recovery, these factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**") and the ongoing global credit and liquidity concerns. This volatility may in the future affect the Corporation's ability to obtain equity or debt financing on acceptable terms.

**Prices, Markets and Marketing**

Numerous factors beyond the Corporation's control do, and will continue to affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance the Corporation's reserves are from pipelines, railway lines, processing and storage facilities, operational problems affecting pipelines, railway lines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Corporation.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States, Canada and Europe, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. A material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and natural gas acquisition, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

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

**Market Price of Common Shares**

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market. Similarly, the market price of the Common Shares of the Corporation could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares of the Corporation will trade cannot be accurately predicted.

**Failure to Realize Anticipated Benefits of Acquisitions and Dispositions**

The Corporation considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses may require substantial management effort, time and resources diverting 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 may be periodically disposed of so the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, may realize less than their carrying value on the financial statements of the Corporation.

**Operational Dependence**

Other companies operate some of the assets in which the Corporation has an interest. The Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

**Project Risks**

The Corporation 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 Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- 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;
- regulatory changes;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget, or at all, and may be unable to market the oil and natural gas that it produces effectively.

**Gathering and Processing Facilities, Pipeline Systems and Rail**

The Corporation 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 Corporation 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 Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation'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 to market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also 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 harm the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. These recommendations include, among others, the imposition of higher standards for all DOT-111 tank cars carrying crude oil and the increased auditing of shippers to ensure they properly classify hazardous materials and have adequate safety plans in place. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add additional costs to the transportation of crude oil by rail.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse effect on the Corporation's ability to process its production and deliver the same for sale.

**Competition**

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

**Cost of New Technologies**

The oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Corporation. There can be no assurance that the Corporation will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by the Corporation or implemented in the future may become obsolete. In such case, the Corporation's business, financial condition and results of operations could be affected adversely and materially. If the Corporation is unable to utilize the most advanced commercially available technology, its business, financial condition and results of operations could also be adversely affected in a material way.

**Alternatives to and Changing Demand for Petroleum Products**

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for oil, natural gas and other liquid hydrocarbons. The Corporation cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows.

**Regulatory**

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See "Industry Conditions". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Corporation will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, the Corporation's business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

**Royalty Regimes**

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic.

**Hydraulic Fracturing**

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the Corporation's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves. While the Corporation has not drilled any wells requiring hydraulic fracturing in the past two years, there can be no guarantee it will not drill some in the future.

**Environmental**

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental legislation, 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 Corporation's business, financial condition, results of operations and prospects.

**Liability Management**

Alberta, Saskatchewan 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 Corporation' 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 – Liability Management Programs".

**Climate Change**

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and which may require the Corporation 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. As a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020. These GHG emission reduction targets are not binding, however. Some of the Corporation's significant 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 Corporation'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 Corporation and its operations and financial condition.

**Variations in Foreign Exchange Rates and Interest Rates**

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect the Corporation's production revenues. Accordingly, Canadian/United States exchange rates could affect the future value of the Corporation's reserves as determined by independent evaluators.

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

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, resulting in a reduced amount available to fund its exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of the Common Shares of the Corporation.

**Substantial Capital Requirements**

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- the Corporation's credit rating (if applicable);
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and the Corporation's securities in particular.

Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

**Additional Funding Requirements**

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. There is risk that if the economy and banking industry experienced unexpected and/or prolonged deterioration, the Corporation's access to additional financing may be affected.

Because of global economic volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

**Credit Facility Arrangements**

The amount authorized under the Credit Facility is dependent on the borrowing base determined by the Corporation's lenders. The Corporation is required to comply with covenants under the Credit Facility which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in the default under the Credit Facility, which could result in the Corporation being required to repay amounts owing thereunder. Even if the Corporation is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under the Credit Facility, the lenders under the Credit Facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Credit Facility may impose operating and financial restrictions on the Corporation that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors, to periodically determine the Corporation's borrowing base. A material decline in commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the Corporation under the Credit Facility. This could result in the requirement to repay a portion, or all, of the Corporation's bank indebtedness.

**Issuance of Debt**

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

**Hedging**

From time to time, the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar. However, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate.

**Availability of Drilling Equipment and Access**

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

**Diluent Supply**

Heavy oil and bitumen are characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the transportation of heavy oil and bitumen. A shortfall in the supply of diluent may cause its price to increase thereby increasing the cost to transport heavy oil and bitumen to market and correspondingly increasing the Corporation's overall operating cost, decreasing its net revenues and negatively impacting the overall profitability of its heavy oil and bitumen projects.

**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. The actual interest of the Corporation in properties may accordingly vary from the Corporation's records. If a title defect does exist, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect the Corporation's title to the oil and natural gas properties the Corporation controls that could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

**Reserve Estimates**

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from such estimated reserves 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 natural gas;
- royalty rates; and
- 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 Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates and such variations could be material.

The estimation 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. Such variations could be material.

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

Actual production and cash flows derived from the Corporation's oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and 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, except as may be specifically stated, has not been updated and therefore does not reflect changes in the Corporation's reserves since that date.

**Insurance**

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

**Geopolitical Risks**

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. Conflicts, or conversely peaceful developments, arising outside of Canada have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of the Corporation's net production revenue.

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

**Dilution**

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

**Management of Growth**

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

**Expiration of Licences and Leases**

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

**Dividends**

The Board of Directors approved an initial monthly dividend payment in January 2012. See "Dividends". The amount of future cash dividends paid by the Corporation, if any, will be subject to the discretion of the Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond the control of the Corporation, the dividend policy of the Corporation from time to time and, as a result, future cash dividends could be reduced or suspended entirely.

The market value of the Common Shares may deteriorate if cash dividends are reduced or suspended. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by the Corporation and potential legislative and regulatory changes. Dividends may be reduced during periods of lower funds from operations, which result from lower commodity prices and any decision by the Corporation to finance capital expenditures using funds from operations.

To the extent that external sources of capital, including the issuance of additional Common Shares, become limited or unavailable, the ability of the Corporation to make the necessary capital investments to maintain or expand petroleum and natural gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that the Corporation is required to use funds from operations to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

**Litigation**

In the normal course of the Corporation'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, related to personal injuries, property damage, property tax, 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 Corporation and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations.

**Aboriginal Claims**

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

**Breach of Confidentiality**

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to the business, operations or affairs of the Corporation. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put the Corporation at competitive risk and may cause significant damage to its business. The harm to the Corporation'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 Corporation 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.

**Income Taxes**

The Corporation files all required income tax returns and believes that it is in full compliance with the provisions of the Tax Act 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 Corporation, 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 natural 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 Corporation. Furthermore, tax authorities having jurisdiction over the Corporation may disagree with how the Corporation calculates its income for tax purposes or could change administrative practices to the Corporation's detriment.

**Seasonality**

The level of activity in the Canadian oil and natural 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. In addition, 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 decreases in the demand for the goods and services of the Corporation.

**Third Party Credit Risk**

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

**Conflicts of Interest**

Certain directors or officers of the Corporation may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA which require a director of officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA. See "Directors and Executive Officers – Conflicts of Interest".

**Reliance on Key Personnel**

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

**Expansion into New Activities**

The operations and expertise of the Corporation's management are currently focused primarily on oil and gas production, exploration and development in the Western Canada Sedimentary Basin. In the future the Corporation may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase the Corporation's exposure to one or more existing risk factors, which may in turn result in the Corporation's future operational and financial conditions being adversely affected.

**Forward-Looking Information May Prove Inaccurate**

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's 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 the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumptions and uncertainties are found under the heading "Reader Advisory Regarding Forward-Looking Statements" of this Annual Information Form.

## DIVIDENDS

Following the completion of the Emerge Acquisition, Twin Butte commenced an initial monthly dividend program in January 2012 whereby a monthly dividend would be paid on or about the 15th day of each month to shareholders of record of the Corporation on the last business day of the preceding month, subject to the Corporation's ongoing financial requirements. Following the completion of the Waseca Acquisition, Twin Butte increased the monthly dividend from $0.015 to $0.016 per issued and outstanding Common Share commencing with the dividend paid on December 17, 2012 to shareholders of record on November 30, 2012. See "Risk Factors – Dividends". The Corporation is a resident in Canada and a taxable public corporation. All dividends paid to shareholders since inception of the dividend program are "eligible" dividends under the Tax Act.

Twin Butte has implemented a dividend reinvestment plan which enables eligible shareholders of Twin Butte to reinvest their cash dividends into additional Common Shares which will be purchased through the facilities of the TSX at prevailing market prices or issued from treasury at 95% of the Average Market Price (as defined in the dividend reinvestment plan) on the applicable dividend payment date. Twin Butte has also implemented a stock dividend program which enables the Corporation to issue Common Shares as payment of all or a portion of dividends declared on the Common Shares for those shareholders of Twin Butte who elect to receive stock dividends instead of cash dividends.

Pursuant to the Credit Facility, the Corporation is restricted from declaring or paying dividends to its shareholders (a) other than in the ordinary course of business, (b) if a borrowing base shortfall, a default or an event of default has occurred and is continuing under the Credit Facility, or (c) if the declaration or payment of such dividend would reasonably be expected to cause or result in a default or event of default under the Credit Facility.

The following is a summary of the monthly dividends made by the Corporation since the commencement of the Corporation's monthly dividend program in January 2012.

| For the Month Ended | Dividend per Common Share (1) | Payment Date |
|---|---|---|
| **2012** | | |
| January | $0.015 | February 15, 2012 |
| February | $0.015 | March 15, 2012 |
| March | $0.015 | April 16, 2012 |
| April | $0.015 | May 15, 2012 |
| May | $0.015 | June 15, 2012 |
| June | $0.015 | July 16, 2012 |
| July | $0.015 | August 15, 2012 |
| August | $0.015 | September 17, 2012 |
| September | $0.015 | October 15, 2012 |
| October | $0.015 | November 15, 2012 |
| November | $0.016 | December 17, 2012 |
| December | $0.016 | January 15, 2013 |
| **2013** | | |
| January | $0.016 | February 15, 2013 |
| February | $0.016 | March 15, 2013 |
| March | $0.016 | April 15, 2013 |
| April | $0.016 | May 15, 2013 |
| May | $0.016 | June 17, 2013 |
| June | $0.016 | July 15, 2013 |
| July | $0.016 | August 15, 2013 |
| August | $0.016 | September 16, 2013 |
| September | $0.016 | October 15, 2013 |
| October | $0.016 | November 15, 2013 |
| November | $0.016 | December 16, 2013 |
| December | $0.016 | January 15, 2014 |
| **2014** | | |
| January | $0.016 | February 18, 2014 |
| February | $0.016 | March 17, 2014 |
| March | $0.016 | April 15, 2014 |

Note:

(1) Represents a dividend per Common Share paid by the Corporation with the exception of on March 17, 2014, the Corporation declared a dividend of $0.016 per Common Share to be paid on April 15, 2014 to shareholders of record on March 31, 2014.

## DESCRIPTION OF CAPITAL STRUCTURE

The authorized capital of Twin Butte consists of an unlimited number of Common Shares and an unlimited number of preferred shares issuable in series, each having the rights, privileges, restrictions and conditions described below. For a complete description of the share capital of the Corporation, reference should be made to the Articles of the Corporation, a copy of which has been filed on SEDAR at www.sedar.com.

### Common Shares

The Common Shares have the following rights, privileges, restrictions and conditions:

*Voting Rights*: Holders of Common Shares shall be entitled to notice of, to attend and to one vote per share held at any meeting of the shareholders of the Corporation (other than meetings of a class or series of shares of the Corporation other than the Common Shares as such).

*Dividends*: Holders of Common Shares shall be entitled to receive dividends as and when declared by the Board of Directors on the Common Shares as a class, subject to prior satisfaction of all preferential rights to dividends attached to shares of other classes of shares of the Corporation ranking in priority to the Common Shares in respect of dividends.

*Ranking*: Holders of Common Shares shall be entitled in the event of any liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or any other distribution of the assets of the Corporation among its shareholders for the purpose of winding-up its affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of the Corporation ranking in priority to the Common Shares in respect of return of capital on dissolution, to share rateably, together with the holders of shares of any other class of shares of the Corporation ranking equally with the Common Shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution.

If the Board of Directors declare a dividend on the Common Shares payable in whole or in part in fully paid and non-assessable Common Shares (the portion of the dividend payable in Common Shares being herein referred to as a "**stock dividend**"), the following provisions shall apply:

(a) unless otherwise determined by the Board of Directors in respect of a particular stock dividend: (i) the number of Common Shares (which shall include any fractional Common Shares) to be issued in satisfaction of the stock dividend shall be determined by dividing (A) the dollar amount of the particular stock dividend, by (B) 95% of the "Average Market Price" of a Common Share on the Toronto Stock Exchange (the "**TSX**"), with the "**Average Market Price**" calculated by dividing the total value of Common Shares traded on the TSX by the total volume of Common Shares traded on the TSX over the five trading day period immediately prior to the payment date of the applicable stock dividend on the Common Shares; and (ii) the value of a Common Share to be issued for the purposes of each stock dividend declared by the Board of Directors shall be deemed to be the Average Market Price of a Common Share;

(b) to the extent that any stock dividend paid on the Common Shares represents one or more whole Common Shares payable to a registered holder of Common Shares, such whole Common Shares shall be registered in the name of such holder. Common Shares representing in the aggregate all of the fractions amounting to less than one whole Common Share which might otherwise have been payable to registered holders of Common Shares by reason of such stock dividend shall be issued to the transfer agent for the Common Shares as the agent of such registered holders of Common Shares. The transfer agent shall credit to an account for each such registered holder all fractions of a Common Share amounting to less than one whole share issued by the Corporation by way of stock dividends in respect of the Common Shares registered in the name of such holder. From time to time, when the fractional interests in a Common Share held by the transfer agent for the account of any registered holder of Common Shares are equal to or exceed in the aggregate one additional whole Common Share, the transfer agent shall cause such additional whole Common Share to be registered in the name of such registered holder and thereupon only the excess fractional interest, if any, will continue to be held by the transfer agent for the account of such registered holder. The Common Shares held by the transfer agent representing fractional interests shall not be voted;

(c) if at any time the Corporation shall have reason to believe that tax should be withheld and remitted to a taxation authority in respect of any stock dividend paid or payable to a shareholder in Common Shares, the Corporation shall have the right to sell, or to require its transfer agent in each case as agent of such shareholder, to sell all or any part of the Common Shares or any fraction thereof so issued to such holder in payment of that stock dividend or one or more subsequent stock dividends through the facilities of the TSX or other stock exchange on which the Common Shares are listed for trading, and to cause the transfer agent to remit the cash proceeds from such sale to such taxation authority (rather than such holder) in payment of such tax to be withheld. This right of sale may be exercised by notice given by the Corporation to such holder and to the Corporation or the transfer agent stating the name of the holder, the number of Common Shares to be sold and the amount of the tax which the Corporation has reason to believe should be withheld. Upon receipt of such notice the transfer agent shall, unless a certificate or other evidence of registered ownership for the Common Shares has at the relevant time been issued in the name of the holder, sell the Common Shares as aforementioned and the Corporation or the transfer agent as applicable, shall be deemed for all purposes to be the duly authorized agent of the holder with full authority on behalf of such holder to effect the sale of such Common Shares and deliver the proceeds therefrom to the applicable taxation authority on behalf of the Corporation. Any balance of the cash sale proceeds not remitted by the Corporation in payment of the tax to be withheld shall be payable to the holder whose Common Shares were so sold by the transfer agent;

(d) if at any time the Corporation shall have reason to believe that the payment of a stock dividend to any holder thereof who is resident in or otherwise subject to the laws of a jurisdiction outside Canada might contravene the laws or regulations of such jurisdiction, or could subject the Corporation to any penalty thereunder or any legal or regulatory requirements not otherwise applicable to the Corporation, the Corporation shall have the right to sell, or to require its transfer agent in each case, as agent of such shareholder, to sell through the facilities of the TSX or other stock exchange on which the Common Shares are listed for trading, the Common Shares or any fraction thereof so issued and to cause the transfer agent to pay the cash proceeds from such sale to such holder. The right of sale shall be exercised in the manner provided in subparagraph (c) above except that in the notice there shall be stated, instead of the amount of the tax to be withheld, the nature of the law or regulation which might be contravened or which might subject the Corporation to any penalty or legal or regulatory requirement. Upon receipt of the notice, the Corporation or the transfer agent shall**,** unless a certificate or other evidence of registered ownership for the Common Shares has at the relevant time been issued in the name of the holder, sell the Common Shares as aforementioned and the Corporation or the transfer agent, as applicable shall be deemed for all purposes to be the duly authorized agent of the holder with full authority on behalf of such holder to effect the sale of such Common Shares and to deliver the proceeds therefrom to such holder;

(e) upon any registered holder of Common Shares ceasing to be a registered holder of one or more Common Shares, such holder shall be entitled to receive from the transfer agent, and the transfer agent shall pay as soon as practicable to such holder, an amount in cash equal to the proportion of the value of one Common Share that is represented by the fraction less than one whole Common Share at that time held by the transfer agent for the account of such holder, and, for the purpose of determining such value, each Common Share shall be deemed to have the value equal to the Average Market Price in respect of the last stock dividend paid by the Corporation prior to the date of such payment; and

(f) for the purposes of the foregoing: (i) the calculation of a fraction of a Common Share payable to a shareholder by way of a stock dividend and the calculation of the Average Market Price shall be computed to six decimal places, and shall be rounded to the nearest sixth decimal place; and (ii) neither the Corporation nor its transfer agent shall have any obligation to register any Common Share in the name of a person, to deliver a certificate or other document representing Common Shares registered in the name of a shareholder or to make a cash payment for fractions of a Common Share, unless all applicable laws and regulations to which the Corporation and/or the transfer agent are, or as a result of such action may become, subject, shall have been complied with to their reasonable satisfaction.

**Preferred Shares**

*Series*: The preferred shares may at any time or from time to time be issued in one or more series. Subject to the provisions of the preferred shares and of the ABCA, the directors of the Corporation may from time to time fix the number of shares in, and determine the designation, rights, privileges, restrictions and conditions attaching to the shares of, each series of preferred shares.

*Ranking*: Holders of preferred shares of each series shall, with respect to the payment of dividends and the distribution of assets or return of capital in the event of liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, or any other return of capital or distribution of assets of the Corporation among its shareholders for the purpose of winding up its affairs, be entitled to preference over the Common Shares and over any other shares of the Corporation ranking by their terms junior to the preferred shares of any series and the preferred shares of any series may also be given such other preferences, not inconsistent with the Articles of the Corporation or the ABCA, over the Common Shares and any other class of shares of the Corporation ranking junior to such preferred shares as may be fixed by the directors of the Corporation.

*Idem*: If any cumulative dividends or other amounts payable on the return of capital in respect of any series of preferred shares are not paid in full, all series of preferred shares shall participate rateably in respect of accumulated dividends and return of capital.

## MARKET FOR SECURITIES

**Trading Price and Volume of Common Shares**

The Common Shares are listed and posted for trading on the TSX under the symbol "TBE". The following table sets forth the high and low sales prices (which are not necessarily the closing prices) and the trading volumes for the Common Shares on the TSX as reported by the TSX for the periods indicated:

| | Price Range ($) | | Trading |
|---|---|---|---|
| **Period** | **High** | **Low** | **Volume** |
| **2013** | | | |
| January | 2.84 | 2.51 | 24,895,309 |
| February | 2.40 | 1.98 | 39,418,870 |
| March | 2.49 | 2.09 | 42,349,542 |
| April | 2.46 | 2.20 | 17,714,204 |
| May | 2.36 | 2.11 | 31,261,850 |
| June | 2.29 | 2.165 | 15,779,278 |
| July | 2.41 | 1.60 | 61,709,474 |
| August | 1.90 | 1.60 | 26,232,509 |
| September | 2.17 | 1.80 | 18,949,063 |
| October | 2.36 | 2.01 | 45,660,093 |
| November | 2.29 | 2.07 | 41,524,622 |
| December | 2.30 | 2.09 | 15,792,325 |
| **2014** | | | |
| January | 2.43 | 2.20 | 20,372,225 |
| February | 2.34 | 2.18 | 19,430,798 |
| March (1 to 20) | 2.36 | 2.28 | 11,679,205 |

**Trading Price and Volume of Convertible Debentures**

The Convertible Debentures are listed and posted for trading on the TSX under the symbol "TBE.DB". The following table sets forth the high and low sales prices (which are not necessarily the closing prices) and the trading volumes for the Convertible Debentures on the TSX (with each unit of volume traded being equal to $100 principal amount for each Convertible Debenture) from December 13, 2013, the date of the initial listing, as reported by the TSX for the periods indicated:

| Period | Price Range ($) High | Price Range ($) Low | Trading Volume |
|---|---|---|---|
| **2013** | | | |
| December (13 to 31) | 99.90 | 95.25 | 69,740 |
| **2014** | | | |
| January | 100.50 | 99.40 | 65,921 |
| February | 101.39 | 99.90 | 82,780 |
| March (1 to 20) | 102.01 | 101.00 | 10,735 |

**Prior Sales of Outstanding Unlisted Securities**

During the year ended December 31, 2013, the only securities which Twin Butte issued which are outstanding but are not listed or quoted on a marketplace were the grant of an aggregate of 2,007,852 restricted awards (entitling the holders to be issued 2,160,619 Common Shares as at December 31, 2013, which includes the value of dividend equivalents that have accumulated on the underlying grants) and an aggregate of 1,185,783 performance awards (entitling the holders to be issued 1,464,479 Common Shares as at December 31, 2013, which includes the value of dividend equivalents that have accumulated on the underlying grants and assumes a payout multiplier of 1x for the grants with the exception of performance awards vesting in 2014 in respect of which a payout multiplier of 1.5x has been assumed) pursuant to Twin Butte's share award incentive plan.

## ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the knowledge of management of the Corporation, none of the securities of the Corporation are held in escrow or are subject to a contractual restriction on transfer as at the date hereof.

## DIRECTORS AND EXECUTIVE OFFICERS

**Name, Occupation and Security Holding**

The following table sets forth certain information in respect to Twin Butte's directors and executive officers:

| Name, Province and Country of Residence | Position(s) with Twin Butte (1) | Principal Occupation During the Five Years Preceding |
|---|---|---|
| David M. Fitzpatrick (3)<br>Alberta, Canada | Chairman and Director | Independent businessman. |
| R. James Brown (2)(3)<br>Alberta, Canada | Director | Independent businessman since January 1, 2009, and prior thereto, Vice President of Fording Canadian Coal Trust, Fording (GP) ULC and Elk Valley Coal Partnership. |
| John A. Brussa (3)<br>Alberta, Canada | Director | Partner, Burnet, Duckworth & Palmer LLP (law firm). |

| Name, Province and Country of Residence | Position(s) with Twin Butte [1] | Principal Occupation During the Five Years Preceding |
|---|---|---|
| Thomas J. Greschner [4]<br>Alberta, Canada | Director | President and Chief Executive Officer of Nexxco Energy Ltd. (oil and gas company) since August 2012; prior thereto, independent businessman from January 9, 2012 until August 2012; and prior thereto, President and Chief Executive of Emerge. |
| Warren D. Steckley [2][4]<br>Alberta, Canada | Director | Independent businessman since September 9, 2013, and prior thereto, President and Chief Operating Officer of Barnwell of Canada, Limited (oil and gas company). |
| William A. Trickett [2][4]<br>Alberta, Canada | Director | President and Chief Executive Officer and director of Fogo Energy Corp. (oil and gas company) since October 14, 2009, and prior thereto, President and Chief Executive Officer of Buffalo Resources Corp. (oil and gas company). |
| James Saunders<br>Alberta, Canada | Chief Executive Officer and Director | Chief Executive Officer of Twin Butte since January 14, 2014 and prior thereto, President and Chief Executive Officer of Twin Butte. |
| R. Alan Steele<br>Alberta, Canada | Vice President, Finance, Chief Financial Officer and Corporate Secretary | Vice President, Finance, Chief Financial Officer and Corporate Secretary of Twin Butte. |
| Bruce W. Hall<br>Alberta, Canada | President and Chief Operating Officer | President and Chief Operating Officer of Twin Butte since January 14, 2014 and Chief Operating Officer of Twin Butte since January 3, 2011; prior thereto, Vice President, Corporate Development of Twin Butte from June 9, 2009 to January 3, 2011, and prior thereto, Vice President, Engineering of Alberta Clipper Energy Inc. (oil and gas company). |
| Robert D. Bowman<br>Alberta, Canada | Vice President, Operations | Vice President, Operations of Twin Butte since June 1, 2010, and prior thereto, President of BCF Resources Ltd. (private oil and gas consulting company). |
| Claude Gamache<br>Alberta, Canada | Vice President, Heavy Oil Geosciences | Vice President, Heavy Oil Geosciences of Twin Butte since January 9, 2012, and prior thereto, Vice President, Exploration of Emerge (oil and gas company). |
| Preston Kraft<br>Alberta, Canada | Vice President, Engineering | Vice President, Engineering of Twin Butte since January 9, 2012; prior thereto, Vice President, Engineering and Operations of Emerge from May 2010 until January 9, 2012, and prior thereto, various roles concluding with General Manager, Heavy Oil Business Unit, with Husky Energy Inc. (oil and gas company). |
| Gord Howe<br>Alberta, Canada | Vice President, Land | Vice President, Land of Twin Butte since January 14, 2013; prior thereto, Vice President, Land and Negotiations of Lone Pine Resources Inc. (oil and gas company) from June 1, 2011 to January 3, 2013; prior thereto, Land Manager of Canadian Forest Oil Ltd. (oil and gas company) from January 2010 to March 2011, and prior thereto, Land Manager, Iteration Energy Ltd. (oil and gas company). |

Notes:

(1) All of the directors of Twin Butte have been appointed to hold office until the next annual general meeting of shareholders or until their successor is duly elected or appointed, unless their office is earlier vacated. Messrs. Fitzpatrick, Brown, Brussa, Greschner,

Steckley, Trickett and Saunders have been directors of Twin Butte since December 8, 2008, February 8, 2008, March 22, 2011, January 9, 2012, July 13, 2009, October 14, 2009 and December 30, 2005, respectively.

(2) Member of the Audit Committee.

(3) Member of the Compensation, Nominating and Corporate Governance Committee.

(4) Member of the Reserves Committee.

(5) Twin Butte does not have an Executive Committee.

As at the date of this Annual Information Form, the number of Common Shares beneficially owned, or controlled or directed, directly or indirectly, by all of the directors and officers of Twin Butte is 8,754,887 million Common Shares, representing approximately 2.54% of the issued and outstanding Common Shares.

**Cease Trade Orders, Bankruptcies, Penalties or Sanctions**

***Cease Trade Orders***

To the knowledge of Twin Butte, no director or executive officer of Twin Butte (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including Twin Butte), that: (a) was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**"), that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

***Bankruptcies***

To the knowledge of Twin Butte, except as described below, no director or executive officer of Twin Butte (nor any personal holding company of any of such persons) or shareholder holding a sufficient number of securities of Twin Butte to affect materially the control of Twin Butte: (a) is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including Twin Butte) that, while that 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 or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the ten years before the date of this Annual Information Form, 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, executive officer or shareholder.

Robert Bowman, the Vice President, Operations of Twin Butte, served as a director of Avatar Energy Ltd. ("**Avatar**"), an oil and gas company, until February 4, 2013. On February 4, 2013, Avatar received a Notice of Intention to Enforce Security from its bank lender and, in connection therewith, it consented to the appointment by the lender of a receiver and manager of Avatar's property. Gordon Howe, the Vice President, Land of Twin Butte, was the Vice President, Land and Negotiations of Lone Pine Resources Inc. ("**Lone Pine**"), an oil and gas company, from June 1, 2011 to January 3, 2013**.** David Fitzpatrick, a director of Twin Butte, has been a director of Lone Pine since June 1, 2011 and was the former Interim Chief Executive Officer of Lone Pine from February 28, 2013 until May 30, 2013. On September 25, 2013, Lone Pine commenced proceedings in the Court of Queen's Bench of Alberta under the *Companies' Creditors Arrangement Act* ("**CCAA**") and ancillary proceedings under Chapter 15 of the United States Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware. On January 31, 2014, Lone Pine completed its emergence from creditor protection under the CCAA and Chapter 15 of the United States Bankruptcy Code. Lone Pine, Lone Pine Resources Canada Ltd. and all other subsidiaries of Lone Pine were parties to the CCAA and Chapter 15 proceedings.

### *Penalties or Sanctions*

To the knowledge of Twin Butte, no director or executive officer of Twin Butte (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of Twin Butte to affect materially the control of Twin Butte, has been subject to: (a) 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 (b) 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

There are potential conflicts of interest to which the directors and officers of the Corporation will be subject in connection with the operations of the Corporation. In particular, certain of the directors and officers of the Corporation are involved in managerial and/or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of the Corporation or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of the Corporation. Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

## LEGAL PROCEEDINGS AND REGULATORY ACTIONS

### Legal Proceedings

None of the Corporation or any of its subsidiaries is a party to any legal proceeding nor was it a party to any legal proceeding during the financial year ended December 31, 2013, nor is the Corporation aware of any contemplated legal proceeding involving the Corporation or its subsidiaries or any of its property which involves a claim for damages exclusive of interest and costs that may exceed 10% of the current assets of the Corporation.

### Regulatory Actions

During the year ended December 31, 2013, there were no (i) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (ii) any other penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision, or (iii) settlement agreements the Corporation entered into before a court relating to securities legislation or with a securities regulatory authority.

## INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There are no material interests, direct or indirect, of any director or executive officer of the Corporation, any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of the Corporation's outstanding voting securities, or any associate or affiliate of any of the foregoing persons or companies, in any transaction within the three most recently completed financial years or during the current financial year which has materially affected or is reasonably expected to materially affect the Corporation, other than as disclosed elsewhere in this Annual Information Form. John Brussa, a director of Twin Butte, is a partner of Burnet, Duckworth & Palmer LLP, which firm receives fees for legal services provided to Twin Butte.

## TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Valiant Trust Company at its principal offices in Calgary, Alberta and Toronto, Ontario.

## MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business (unless otherwise required by applicable securities requirements to be disclosed), the Corporation has not entered into any material contracts during the last financial year, or before the last financial year which are still in effect, other than:

1. the credit agreement with respect to the Credit Facility as described above under "General Development of the Business – Three Year History – Year Ended December 31, 2013" and in note 11 to the audited financial statements of the Corporation for the year ended December 31, 2013; and

2. the convertible debenture indenture dated as of December 13, 2013 between Twin Butte and Valiant Trust Company creating the Convertible Debentures, as described above under "General Development of the Business – Three Year History – Year Ended December 31, 2013" and in note 12 to the audited financial statements of the Corporation for the year ended December 31, 2013.

Copies of these documents have been filed on SEDAR at www.sedar.com.

## INTERESTS OF EXPERTS

### Names of Experts

The only persons or companies who are 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 National Instrument 51-102 by the Corporation during, or relating to, the Corporation's most recently completed financial year, and whose profession or business gives authority to the report, valuation statement or opinion made by the person or company, are PricewaterhouseCoopers LLP, the Corporation's independent auditors, MacKay LLP, Black Shire's independent auditors, McDaniel, the Corporation's independent engineering evaluators and GLJ Petroleum Consultants Ltd., Black Shire's independent engineering evaluators.

### Interests of Experts

To the Corporation's knowledge, there were no registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of one of its associates or affiliates: (i) held by McDaniel or by the "designated professionals" (as defined in Form 51-102F2 to National Instrument 51-102) of McDaniel, when McDaniel prepared the report, valuation, statement or opinion referred to herein as having been prepared by McDaniel; (ii) received by McDaniel or by the "designated professionals" of McDaniel, after the time specified above; or (iii) to be received by McDaniel or by the "designated professionals" of McDaniel; except in each case for the ownership of Common Shares, which in respect of McDaniel and McDaniel's "designated professionals", as a group, has at all relevant times represented less than one percent of the outstanding Common Shares. In addition, neither McDaniel, nor any director, officer or employee of McDaniel, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

PricewaterhouseCoopers LLP is independent of the Corporation within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta. Neither PricewaterhouseCoopers LLP nor any director, officer or employee of PricewaterhouseCoopers LLP is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

## AUDIT COMMITTEE INFORMATION

### Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Audit Committee of the Board of Directors is attached hereto as Schedule "C".

### Composition of the Audit Committee

The Audit Committee of the Corporation is currently comprised of R. James Brown (Chair), Warren D. Steckley and William A. Trickett. The following table sets out the assessment of each Audit Committee member's independence, financial literacy and relevant educational background and experience supporting such financial literacy.

| Name and Municipality of Residence | Independent | Financially Literate | Relevant Education and Experience |
|---|---|---|---|
| R. James Brown<br>Calgary, Alberta | Yes | Yes | Mr. Brown's education and experience relevant to the performance of his responsibilities as an Audit Committee member are derived from his experience as Vice President (from April 2008 until December 2008) and Vice President and Chief Financial Officer of Fording Canadian Coal Trust, Fording (GP) ULC and Elk Valley Coal Partnership from October 2005 until April 2008; prior thereto, Vice President, Finance and Chief Financial Officer of High Point Resources Ltd. (oil and gas company) from March 2004 to August 2005; and prior thereto, Vice President, Finance and Chief Financial Officer of Terraquest Energy Inc. (oil and gas company). He has over 25 years of experience in the oil and gas industry, including ten years as Chief Financial Officer with High Point Resources Inc., Dorset Exploration Ltd., Richland Petroleum Inc., and Terraquest Energy Inc. He has also developed practical experience and understanding of procedures for financial reporting from his service on boards and audit committees of numerous publicly traded companies. Mr. Brown holds a Bachelor of Commerce degree from the University of Calgary and is a Chartered Accountant. |
| Warren D. Steckley<br>Calgary, Alberta | Yes | Yes | Mr. Steckley's education and experience relevant to the performance of his responsibilities as an Audit Committee member are derived from his combination of more than 30 years of oil and gas industry experience with financial and investment expertise. From 1998 until September 9, 2013, Mr. Steckley was the President and Chief Operating Officer of Barnwell of Canada, Limited, an oil and gas company and wholly-owned subsidiary of Barnwell Industries Inc., a company listed on the American Stock Exchange. Prior thereto, Mr. Steckley spent five years in corporate finance at PowerWest Financial Ltd. (now ARC Resources Ltd.). Through his interaction with Chief Financial Officers over the years, Mr. Steckley has developed practical experience and understanding of procedures for financial reporting. He has also developed practical experience and understanding of procedures for financial reporting from his service on boards and audit committees of numerous publicly traded companies. Mr. Steckley is a Professional Engineer with a BSc. in Mechanical Engineering from the University of Alberta and a Master of Business Administration from the University of Alberta. |

| Name and Municipality of Residence | Independent | Financially Literate | Relevant Education and Experience |
|---|---|---|---|
| William A. Trickett<br>Calgary, Alberta | Yes | Yes | Mr. Trickett's education and experience relevant to the performance of his responsibilities as an audit committee member are derived from his 45 years of experience in the oil and gas industry. Mr. Trickett is currently President and Chief Executive Officer and director of Fogo Energy Corp., a private oil and gas company; prior thereto, was President and Chief Executive Officer and director of Buffalo Resources Corp., an oil and gas company listed on the TSX; and prior thereto, from 1987 to 1996, Mr. Trickett was President, Chief Executive Officer and a director of Morgan Hydrocarbons Inc., an oil and gas company formerly listed on the TSX, the Montreal Stock Exchange and the New York Stock Exchange. Through his interaction with Chief Financial Officers over the years, Mr. Trickett has developed practical experience and understanding of procedures for financial reporting. He has also developed practical experience and understanding of procedures for financial reporting from his service on boards of numerous publicly traded companies. Mr. Trickett obtained a BSc. in Mathematics and Physics in 1968 from Memorial University in Newfoundland and a BSc. in Chemical Engineering from Nova Scotia Technical College, Halifax, Nova Scotia in 1970. |

**Pre-Approval of Policies and Procedures**

Under the Mandate and Terms of Reference of the Audit Committee, the Audit Committee is required to review and pre-approve any non-audit services to be provided to the Corporation or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Audit Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member report to the Audit Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Audit Committee from time to time.

The Audit Committee has determined that in order to ensure the continued independence of the auditors, only limited non-audit related services will be provided to the Corporation by PricewaterhouseCoopers LLP and in such case, only with the prior approval of the Audit Committee.

**External Auditors Service Fees**

The following table sets forth the audit service fees billed by Twin Butte's external auditors, PricewaterhouseCoopers LLP, for the periods indicated:

| Type of Fees and Fiscal Year Ended | Aggregate Fees Billed | Description of Services |
|---|---|---|
| **Audit Fees** [(1)] | | |
| Fiscal Year Ended December 31, 2013 | $192,000 | Audit of financial statements and review of interim financial statements |
| Fiscal Year Ended December 31, 2012 | $205,000 | Audit of financial statements and review of interim financial statements |
| **Audit – Related Fees** [(2)] | | |
| Fiscal Year Ended December 31, 2013 | $52,000 | Review of documents for Black Shire Acquisition and prospectuses in connection with the Subscription Receipt Offering and the offering of $85 million aggregate principal amount of Convertible Debentures |
| Fiscal Year Ended December 31, 2012 | $24,000 | Review of documents for Avalon Acquisition and Waseca Acquisition |

| Type of Fees and Fiscal Year Ended | Aggregate Fees Billed | Description of Services |
|---|---|---|
| **Tax Fees** [(3)] | | |
| Fiscal Year Ended December 31, 2013 | $Nil | |
| Fiscal Year Ended December 31, 2012 | $Nil | |
| **All Other Fees** [(4)] | | |
| Fiscal Year Ended December 31, 2013 | $Nil | |
| Fiscal Year Ended December 31, 2012 | $Nil | |

Notes:

(1) "Audit Fees" include fees necessary to perform the annual audit and quarterly reviews of the Corporation'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 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 includes 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.

## ADDITIONAL INFORMATION

Additional information relating to Twin Butte may be found on SEDAR at www.sedar.com.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Twin Butte's securities and securities authorized for issuance under equity compensation plans will be contained in Twin Butte's information circular – proxy statement relating to the annual meeting of shareholders to be held on May 15, 2014.

Additional information is also provided in Twin Butte's financial statements and management's discussion and analysis for the year ended December 31, 2013, which documents may be found on SEDAR at www.sedar.com.

## SCHEDULE "A"

## REPORT ON RESERVES DATA BY MCDANIEL & ASSOCIATES CONSULTANTS LTD. IN ACCORDANCE WITH FORM 51-101F2

To the Board of Directors of Twin Butte Energy Ltd. (the "**Corporation**"):

1. We have evaluated and reviewed the Corporation's reserves data as at December 31, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

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

   We carried out our evaluation and review 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 and review to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation and review 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 Corporation evaluated and reviewed by us for the year ended December 31, 2013, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Corporation's management:

| **Independent Qualified Reserves Evaluator** | **Description and Preparation Date of Evaluation Report** | **Location of Reserves (Country or Foreign Geographic Area)** | **Net Present Value of Future Net Revenue ($ thousands – before income taxes, 10% discount rate)** | | | |
|---|---|---|---|---|---|---|
| | | | **Audited** | **Evaluated** | **Reviewed** | **Total** |
| McDaniel & Associates Consultants Ltd. | Evaluation and review of P&NG Reserves of Twin Butte Energy Ltd. as at December 31, 2013, prepared February 28, 2014 | Canada | - | 1,031,593 | 111,261 | 1,142,854 |

5. In our opinion, the reserves data respectively evaluated and reviewed by us have, in all material respects, been determined and are 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 our report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

**McDaniel & Associates Consultants Ltd.**, Calgary, Alberta, Canada, February 28, 2014.

Per: (Signed) P.A. Welch, P.Eng
P.A. Welch, P.Eng
President and Managing Director

## SCHEDULE "B"

## REPORT OF TWIN BUTTE MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE IN ACCORDANCE WITH FORM 51-101F3

Management of Twin Butte Energy Ltd. (the "**Corporation**") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved and probable reserves and related future net reserves as at December 31, 2013, estimated using forecast prices and costs.

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

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

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves 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 of the Corporation has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101 F1 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 judgments regarding future events, actual results will vary and the variations may be material.

DATED as of March 21, 2014.

(Signed) James Saunders
Chief Executive Officer

(Signed) Bruce W. Hall
President and Chief Operating Officer

(Signed) Warren Steckley
Director and Chairman of the Reserves Committee

(Signed) Thomas J. Greschner
Director and Member of the Reserves Committee

**SCHEDULE "C"**

**TWIN BUTTE ENERGY LTD.**

**AUDIT COMMITTEE**

**MANDATE AND TERMS OF REFERENCE**

**Role and Objective**

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Twin Butte Energy Ltd. ("**Twin Butte**" or the "**Corporation**") to which the Board has delegated its responsibility for the oversight of the following:

1. nature and scope of the annual audit;
2. the oversight of management's reporting on internal accounting standards and practices;
3. the review of financial information, accounting systems and procedures; and
4. financial reporting and financial statements,

and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

1. to assist directors of Twin Butte in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;
2. to facilitate communication between directors and the external auditors;
3. to consider the external auditor's independence;
4. to consider the credibility and objectivity of financial reports; and
5. to preserve the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and the external auditors.

**Membership of Committee**

1. The Committee will be comprised of at least three (3) directors of Twin Butte or such greater number as the Board may determine from time to time and all members of the Committee shall be "independent" (as such term is used in National Instrument 52-110 – Audit Committees ("**NI 52-110**") unless the Board determines that the exemption contained in NI 52-110 is available and determines to rely thereon.
2. The Board may from time to time designate one of the members of the Committee to be the Chair of the Committee.
3. All of the members of the Committee must be "financially literate" (as defined in NI 52-110) unless the Board determines that an exemption under NI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of NI 52-110.

**Mandate and Responsibilities of Committee**

It is the responsibility of the Committee to:

1. Oversee the work of the external auditors, including the resolution of any disagreements between management and the external auditors regarding financial reporting.

2. Satisfy itself on behalf of the Board with respect to Twin Butte's internal control systems.

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

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

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

5. Review and approve the disclosure of audit committee information required to be included in the AIF of the Corporation prior to its filing with regulatory authorities.

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

   - recommend to the Board the external auditors to be nominated;
   - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;
   - on an annual basis, assess the reasonableness of the audit fee;
   - on an annual basis, conduct an assessment of the external auditor's performance;
   - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;

- when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
- review and pre-approve any non-audit services to be provided to Twin Butte or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member(s) report to the Committee at the next scheduled meeting such pre-approval and the member(s) comply with such other procedures as may be established by the Committee from time to time.

7. Review with the external auditors (and internal auditor if one is appointed by Twin Butte) their assessment of the internal controls of Twin Butte, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee will also review annually with the external auditors their plan for their audit and consider the impact of business risks of the Corporation on the audit plan. The Committee will monitor the execution of the audit plan, with emphasis on the more complex and risky areas of the audit. Upon completion of the audit, the Committee will review annually with the external auditors their reports upon the financial statements of Twin Butte and its subsidiaries and the Committee will evaluate the audit findings contained in the audit report.

8. Review with the external auditors on an annual basis the Canadian Public Accountability Board's ("**CPAB**") public inspection results report and, in a year when the Corporation's file is inspected by CPAB, the Committee will also review with the external auditors the inspection findings contained in such report.

9. Review risk management policies and procedures of Twin Butte (i.e. hedging, litigation and insurance) and consider the impact of business risks on the audit plan.

10. Establish a procedure for:
    - the receipt, retention and treatment of complaints received by Twin Butte regarding accounting, internal accounting controls or auditing matters; and
    - the confidential, anonymous submission by employees of Twin Butte of concerns regarding questionable accounting or auditing matters.

11. Review and approve Twin Butte's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of the Corporation.

12. Complete a comprehensive review of the external audit firm on a periodic basis, once every five years at minimum, which comprehensive review will generally include an evaluation of the following:
    - trends in the audit firm's performance, industry expertise and professional skepticism;
    - the quality control environment of the audit firm, including safeguards against independent threats;
    - the quality of thought, leadership and transparency of communications on any controversial matters;
    - the results of annual assessments, how the firm has responded to those assessments and how the firm handled any partner rotations during the period; and
    - the quality of the engagement team.

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

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

**Meetings and Administrative Matters**

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

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

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

4. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer of Twin Butte will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

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

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

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

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

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

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

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