



ANNUAL INFORMATION FORM
For the Year Ended December 31, 2013

March 26, 2014

TABLE OF CONTENTS

THE CORPORATION.....	4
Intercorporate Relationships	4
GENERAL DEVELOPMENT OF THE BUSINESS	4
Business of the Corporation	4
Corporate Strategy	4
History of the Corporation	4
Environmental Matters	6
Employees	6
Competitive Conditions	6
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION	6
Petroleum and Natural Gas Reserves	6
RESERVE REPORT PRICING ASSUMPTIONS	9
Forecast Prices and Costs Employed by GLJ - December 31, 2013	9
RECONCILIATION OF CHANGES IN RESERVES	11
Reserves Reconciliation	11
ADDITIONAL INFORMATION RELATING TO RESERVES DATA.....	11
Undeveloped Reserves	11
Significant Factors or Uncertainties Affecting Reserves Data	13
Future Development Costs	13
OTHER OIL AND GAS INFORMATION	14
Oil and Gas Assets	14
Properties with No Attributed Reserves	17
Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves	17
Forward Contracts	17
Income Tax Horizon	18
Costs Incurred	18
Exploration and Development Activities	19
Production Estimates	19
Production History	19
Netback History	19
Production Volume by Field	20
RISK FACTORS	20
Uncertain Discovery of Viable Commercial Prospects	20
Volatility of Oil and Natural Gas Contracts	21
Exploration, Development and Production Risks	21
Prices, Markets and Marketing of Crude Oil and Natural Gas	21
Global Economic Conditions	22
Capital Markets	22
Royalty Regime	22
Substantial Capital Requirements; Liquidity	23
Competition	23
Shortage of Supplies and Equipment	23
Interruption from Severe Weather	23
Dependence on Third-Party Pipelines and Gathering and Processing Facilities	23
Operating Hazards and Uninsured Risks	24
Restoration, Safety and Environmental Risks	24

Expiration of Licenses and Leases	24
Title	24
Environmental Risks	25
Reserve Estimates	25
Operational Dependence	25
Reserve Replacement	26
Reliance on Key Employees	26
Corporate Matters.....	26
Management of Growth	26
Permits and Licences.....	26
Additional Funding Requirements	26
Variations in Foreign Exchange Rates	26
Issuance of Debt.....	27
Financial Instruments	27
Availability of Drilling Equipment and Access Restrictions	27
Aboriginal Claims	27
Seasonality	27
Third Party Credit Risk	27
Alternatives to and Changing Demand for Petroleum Products.....	28
Emission Regulation	28
Environmental Regulation.....	28
INDUSTRY CONDITIONS.....	28
Canadian Government Regulation	28
Pricing and Marketing – Oil.....	28
Pricing and Marketing – Natural Gas.....	29
The North American Free Trade Agreement.....	29
Provincial Royalties and Incentives	29
Land Tenure	32
Environmental Regulation.....	33
Environmental Risks	34
Emission Regulation	35
DIVIDENDS OR DISTRIBUTIONS	35
DESCRIPTION OF SHARE CAPITAL.....	35
Common Shares	35
Preferred Shares	35
MARKET FOR SECURITIES.....	36
Price Range and Volume of Trading of Common Shares	36
ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER	36
DIRECTORS AND OFFICERS.....	36
CEASE TRADE ORDERS, BANKRUPTCIES, PENALTIES OR SANCTIONS	37
AUDIT COMMITTEE INFORMATION	38
LEGAL PROCEEDINGS	39
REGULATORY ACTIONS.....	39
INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS.....	39
TRANSFER AGENT AND REGISTRAR	39
MATERIAL CONTRACTS	39
INTERESTS OF EXPERTS	39
CONFLICTS.....	40

ADDITIONAL INFORMATION.....	40
APPENDIX A FORM 51-101F2.....	41
APPENDIX B FORM 51-101F3.....	43
APPENDIX C DEFINITIONS USED FOR RESERVE CATEGORIES	45
APPENDIX D AUDIT COMMITTEE CHARTER.....	47

ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrels
mdbl	thousand barrels
mdbl	million barrels
bbl/d	barrels of oil per day
API	American Petroleum Institute
NGLs	natural gas liquids
stb	standard stock tank barrel
mstb	thousand standard stock tank barrels

Natural Gas

mcf	thousand cubic feet
mmcf	million cubic feet
mcf/d	thousand cubic feet per day
mmcf/d	million cubic feet per day
mmbtu	million British thermal units
GJ	gigajoule
GJ/d	gigajoules per day
H ₂ S	hydrogen sulfide

Other

boe	barrel of oil equivalent converting six mcf of natural gas to one barrel of oil (6:1)
boe/d	barrels of oil equivalent per day
km	kilometre
mboe	thousand of barrels of oil equivalent
M\$	thousands of dollars
MM\$	millions of dollars
NPV	net present value
OPEC	Organization of Petroleum Exporting Countries

In this Annual Information Form the calculation of barrels of oil equivalent (boe) is calculated at a conversion rate of 6,000 cubic feet (mcf) of natural gas for one barrel (bbl) of oil based on an energy equivalency conversion method. Boes may be misleading particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable to the burner tip and does not represent a value equivalency at the wellhead. Given that 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 on a 6:1 basis may be misleading as an indication of value.

Information contained in this Annual Information Form regarding well-test results is not necessarily indicative of long-term performance of ultimate recovery.

CURRENCY

In this Annual Information Form, unless otherwise noted, all dollar amounts are expressed in Canadian dollars.

FORWARD-LOOKING STATEMENTS

Certain statements and information contained in this Annual Information Form and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events or the Corporation's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Corporation believes that the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or, as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be. The Corporation does not intend, and does not assume any obligation, to update or revise these forward-looking statements except as required pursuant to applicable securities laws.

Forward-looking information and statements are included throughout this Annual Information Form (and the documents incorporated by reference herein) including under the headings "General Development of the Business", "Statement of Reserves Data and Other Oil and Gas Information", "Additional Information Relating to Reserves Data", "Other Oil and Gas Information", "Risk Factors" and "Industry Conditions" and include, but are not limited to, statements pertaining to the following:

- any estimate of present value or future cash flow;
- drilling inventory, drilling plans and timing of drilling, re-completion and tie-in of wells;
- plans for facilities construction and completion and the timing and method of funding thereof;
- productive capacity of wells, anticipated or expected production rates and anticipated dates of commencement of production;
- drilling, completion and facilities costs;
- results of various projects of Terra Energy;
- timing of receipt of regulatory approvals;
- effect of production increases on operating costs per boe;
- ability to lower cost structure in certain projects of Terra Energy;
- growth expectations within Terra Energy;
- timing of development of undeveloped reserves;
- the tax horizon and taxability of Terra Energy;
- supply and demand for oil, natural gas liquids and natural gas;
- the performance and characteristics of Terra Energy's oil and natural gas properties;
- Terra Energy's acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived there from;
- the impact of Canadian federal and provincial governmental regulation on Terra Energy relative to other oil and gas issuers of similar size;
- realization of the anticipated benefits of acquisitions and dispositions;
- weighting of production between different commodities;
- the quantity and quality of the oil and natural gas reserves;
- projections of commodity prices and costs;
- expectations regarding the Corporation's ability to raise capital and continually add reserves through acquisition and development;
- expected levels of royalty rates, operating costs, general and administrative costs, costs of services and other costs and expenses;
- capital expenditure programs and the timing and method of financing thereof; and
- treatment under government regulation and taxation regimes.

The Corporation's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- the ability of the Corporation to conform to the conditions of its lending facility;
- general economic and business conditions in Canada, the United States and globally;
- the ability of management of the Corporation to execute its business plan;
- fluctuations in the price of oil and natural gas, interest and exchange rates;
- the risks of the oil and gas industry both domestically and internationally, such as operational risks in exploring for, developing and producing crude oil and natural gas and market demand;
- actions taken by governmental authorities, including increases in taxes and changes in government regulations and incentive programs;
- geological, technical, drilling and processing problems;
- risks and uncertainties involving geology of oil and gas deposits;
- risks inherent in marketing operations, including credit risk;
- the ability to enter into or renew leases;
- the uncertainty of estimates and projections relating to production, costs and expenses;
- potential delays or changes in plans with respect to exploration or development projects or capital expenditures;
- availability of sufficient financial resources to fund the Corporation's capital expenditures;
- uncertainty of finding reserves, developing and marketing those reserves;
- unanticipated operating events, which could reduce production or cause production to be shut-in or delayed;
- failure to realize the anticipated benefits of acquisitions and incorrect assessments of the value of acquisitions;
- ability to locate satisfactory properties for acquisition or participation;
- shut-ins of connected wells resulting from extreme weather conditions;
- insufficient storage or transportation capacity;
- hazards such as fire, explosion, blowouts, cratering and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury;

- encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations;
- the ability to add production and reserves through development and exploration activities;
- the possibility that government policies or laws, including laws and regulations related to the environment, may change or governmental approvals may be delayed or withheld;
- uncertainty in amounts and timing of royalty payments;
- uncertainties inherent in estimating quantities of oil and natural gas reserves and cash flows to be derived therefrom;
- failure to obtain industry partner and other third party consents and approvals, as and when required;
- stock market volatility and market valuations;
- competition for, among other things, capital, acquisition of reserves, undeveloped land and skilled personnel;
- competition for and inability to retain drilling rigs and other services; and
- the other factors considered under “Risk Factors” in this Annual Information Form and other risk factors identified in other documents incorporated herein by reference.

These factors should not be considered exhaustive. Statements relating to “reserves” or “resources” are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future. With respect to forward-looking statements contained or incorporated by reference in this Annual Information Form, Terra Energy has made assumptions regarding: future exchange rates; energy markets and the price of oil and natural gas; the impact of increasing competition; condition in general economic and financial markets; availability of drilling and related equipment; availability of skilled labour; availability of prospective drilling rights; current technology; cash flow; commodity prices; production rates; effects of regulation and tax laws by governmental agencies; future operating costs and the Corporation’s ability to obtain financing on acceptable terms. In addition, forward-looking statements in documents incorporated by reference herein may be based on additional assumptions as disclosed in such documents. Readers are cautioned that the foregoing list of factors is not exhaustive.

The above summary of assumptions and risks related to forward-looking information has been provided in this Annual Information Form and the documents incorporated by reference herein in order to provide readers with a more complete perspective on Terra Energy’s future operations. Readers are cautioned that this information may not be appropriate for other purposes.

The forward-looking statements contained in this Annual Information Form and the documents incorporated by reference herein are expressly qualified by this cautionary statement.

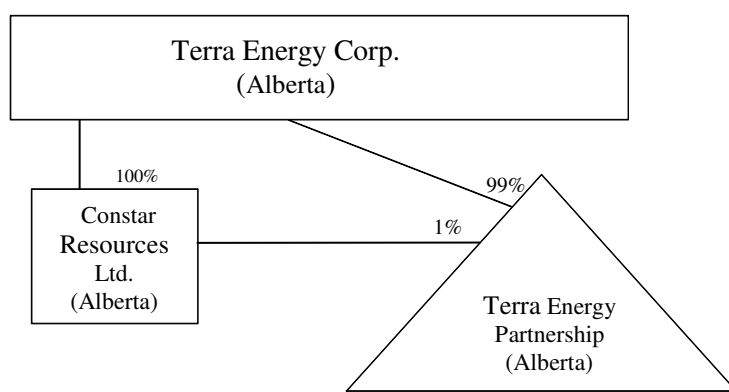
THE CORPORATION

Terra Energy Corp. (“Terra Energy” or the “Corporation”) was amalgamated pursuant to the *Alberta Business Corporations Act* (“ABCA”) on January 30, 2004 (the “Terra Energy Amalgamation”). One of the amalgamating predecessor corporations, Rhodes Resources Corp. (“Rhodes”), was continued under the ABCA on November 1, 2002. The other amalgamating corporations, Terrapet Energy Corp. (“Terrapet”) and Terra Energy Corp. were incorporated pursuant to the ABCA.

The head and registered office of the Corporation is located at Suite 970, 333-7th Ave S.W., Calgary, Alberta T2P 2Z1.

Intercorporate Relationships

The following diagram sets forth the names of the significant subsidiaries of the Corporation, the percentage of voting securities owned by the Corporation and the jurisdiction of incorporation or continuance of each subsidiary as of the date hereof. Terra Energy and Constar Resources Ltd., an Alberta Corporation, are partners in the Terra Energy partnership, a general partnership which carries on oil and gas exploration, development and production activities utilizing the assets of the partners.



GENERAL DEVELOPMENT OF THE BUSINESS

Business of the Corporation

The Corporation is an oil and gas exploration, development and production company operating primarily in the Western Canadian Sedimentary Basin.

Corporate Strategy

Terra Energy expects to grow through a combination of low-risk exploitation and high-impact exploration drilling. Terra Energy will, however, consider additional growth opportunities through business combinations, the acquisition of oil and gas properties, acquisition of undeveloped lands and through additional development and exploratory drilling. Growth will be funded through cash flow, increased debt, equity offerings and/or asset rationalizations.

History of the Corporation

2011

In November of 2010 Terra Energy engaged GMP Securities and Scotia Capital Inc., as joint financial advisors, to assist the Corporation in securing private equity for the Corporation’s Montney operations. The marketing process and related negotiations continued throughout 2011 without success.

In November 2011, Terra Energy announced the expansion of its efforts to secure alternate forms of capital, including capital from Asia and Europe, to develop its unconventional Montney gas assets. Alternatively, the Corporation considered the outright sale of the Montney assets to strategic players.

Terra Energy also engaged Macquarie Capital Markets Canada Ltd. (“Macquarie Capital”) to market certain specified assets located in west-central Alberta in the Karr, North Ante Creek, Peoria and Sturgeon Lake areas. These assets are non-core to Terra

Energy and have no production or reserves currently attributed to them. Included in this marketing process are Terra Energy's Duvernay assets.

In December 2011, Terra Energy formally engaged Macquarie Capital and Scotia Waterous Capital Inc., jointly as marketing and financial advisors to assist the Corporation in connection with an outright sale or joint venture of its unconventional Montney assets located in northeast British Columbia. The Corporation also engaged GMP Securities LP to assist the Corporation in the analysis and evaluation of any proposed transactions.

2012

On May 29, 2012, the Corporation disposed its 100 percent interest in a gathering system to an industry partner for net proceeds of \$8 million. The \$6 million of the proceeds were utilized by the Corporation to reduce its credit facility from \$100 million to \$94 million.

Throughout the first and second quarter of 2012, natural gas prices continued to deteriorate reaching 10 year lows in April of 2012. As a result of both current and future natural gas price forecasts, the underlying value of the assets supporting the Corporation's lending facility were eroded to levels not supportive of the debt drawn. The Corporation's lending facility was reviewed in June of 2012 at which time the syndicate of lenders required the Corporation to take action which would result in a further reduction of the Corporation's credit facility. On November 6, 2012 the board of directors resolved to proceed with the sale of assets with a view to substantially pay down the Corporation's indebtedness with senior lenders and other creditors, and not to proceed with subordinate financing. Management was authorized to proceed with asset sales in excess of \$80 million.

During the third quarter, the Corporation successfully closed the sale of a non-producing oil and gas property located in the Wembley area of Alberta for gross proceeds of \$6.1 million and applied the net proceeds of the sale to the credit facility, thereby reducing it from \$94 million to \$88 million.

In November 2012, the Corporation continued to market and sell non-core and non-producing assets resulting in proceeds of \$1.9 million.

On December 14, 2012, the Corporation successfully completed the initial portion of a \$78 million sale of its Montney petroleum and natural gas rights for \$22 million, plus adjustments. The net proceeds were utilized to reduce the Corporation's bank facility from \$88 million to \$70 million. The initial portion of the transaction included the Corporation's Montney assets located in Monias and Groundbirch, British Columbia.

2013

On February 28, 2013 the Corporation completed the second stage of the transaction involving Montney assets located in Stoddart, Eagle and Attachie to an industry partner for \$20 million gross proceeds. On July 9, 2013, the Corporation completed, with the same industry partner, the third and final stage of the transaction involving Montney assets in Altares, Hudson and Mica for gross proceeds of \$36 million. The proceeds from these transactions were utilized to reduce Corporation's bank facility from \$70 million to approximately \$14.5 million.

On December 18, 2013, Terra Energy entered into a new \$25 million secured lending facility (the "Facility") with a senior Canadian chartered bank. The Facility is comprised of a \$22.5 million revolving operating demand line and a \$2.5 million non-revolving acquisition/development demand line with an annual renewal date of May 1. The proceeds of the Facility were utilized to payout and replace the Corporation's former lending facility, with the balance being available to be applied towards working capital.

Subsequent Events

On January 14, 2014, the \$22.5 million revolving operating demand line was funded from the new Facility, and the Corporation paid out the \$14.5 million of its previous lending facility. The non-revolving acquisition /development demand line was funded in the amount of \$2.3 million on March 3, 2014.

On February 14, 2014, the Corporation announced that its Board of Directors had approved approximately \$14.3 million for its 2014 capital expenditure (CAPEX) program to fund its exploration and development activities. The CAPEX plan will be primarily focused on a number of pipeline projects to tie-in existing wells and re-completion projects targeting oil and natural gas liquids.

On February 21, 2014, Terra Energy announced a non-brokered private placement offering of up to \$1.25 million comprised of units of the Corporation ("Units"), consisting of one common share of the Corporation ("Common Share") and one Common Share

purchase warrant ("Warrant"), and Common Shares of the Corporation to be issued on a "flow-through" basis ("Flow-Through Shares"), at a price of \$0.40 per Unit and \$0.40 per Flow-Through Share, resulting in the issuance of up to an aggregate of 3,125,000 Units and Flow-Through Shares (the "Offering"). Each Warrant is exercisable into one Common Share at a price of \$0.50 per Common Share on or before June 30, 2015.

The gross proceeds of the Flow-Through Shares will be used by the Corporation to incur eligible Canadian development expenses ("Qualifying Expenditures") prior to December 31, 2015 on Terra Energy's properties. The Corporation will renounce the Qualifying Expenditures to subscribers of the Flow-Through Shares for the fiscal year ended December 31, 2014. The net proceeds of the Units will be used to partially fund Terra Energy's 2014 capital expenditure programs and for general working capital purposes.

On February 25, 2014, Terra Energy announced that it had increased the size of the Offering from \$1.25 million to \$2 million of Units and Flow-Through Shares resulting in the issuance of up to and aggregate of 5,000,000 Units and Flow-Through Shares.

On February 27, 2014, the Corporation closed the first tranche of the Offering pursuant to the issuance of 1,755,000 Units and 2,000,000 Flow-Through Shares resulting in aggregate gross proceeds of \$1,502,000.

On March 14, 2014, the Corporation closed the second and final tranche of the Offering pursuant to the issuance of 645,000 Units and 600,000 Flow-Through Shares resulting in aggregate gross proceeds of \$498,000 for the second tranche and \$2 million aggregate gross proceeds for the entire Offering.

Environmental Matters

The oil and gas industry is subject to environmental regulations pursuant to applicable legislation. Such legislation provides for restrictions and prohibitions on release or emission of various substances produced in association with certain oil and gas industry operations, and requires that well and facility sites be abandoned and reclaimed to the satisfaction of environmental authorities. Terra Energy recorded an estimated provision on its balance sheet of \$32.7 million for reserve and abandonment site restoration as at December 31, 2013. The Corporation maintains an insurance program consistent with industry practice to protect against losses due to accidental destruction of assets, well blowouts, pollution and other operating accidents or disruptions. The Corporation also has operational and emergency response procedures and safety and environmental programs in place to reduce potential loss exposure. See "*INDUSTRY CONDITIONS – ENVIRONMENTAL REGULATION*".

Employees

At December 31, 2013, Terra Energy's work force consisted of 26 employees located at head office in Calgary, Alberta and field office in Fort St. John, B.C.

Competitive Conditions

The oil and natural gas industry is intensely competitive in all its phases. Terra Energy 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. Terra Energy's competitors include resource companies which have greater financial resources, staff and facilities than those of Terra Energy. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Terra Energy 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. See "*RISK FACTORS - COMPETITION*".

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Petroleum and Natural Gas Reserves

GLJ Petroleum Consultants Ltd. ("GLJ"), independent petroleum engineers of Calgary, Alberta, prepared a Reserves Assessment and Evaluation of Canadian Oil and Gas Properties - Corporate Summary and Property Reports and a corporate evaluation dated February 26, 2014 of Terra Energy's oil and gas reserves (the "GLJ Report") which evaluation is effective December 31, 2013. The GLJ Report is in respect of Terra Energy's core oil and gas properties. In preparing its report, GLJ obtained basic information from Terra Energy, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluation and upon which the GLJ Report is based, was obtained from public records, other operators and from GLJ's non-confidential files. The extent and

character of ownership and the accuracy of all factual data supplied for the independent evaluation, from all sources, was accepted by GLJ as represented.

The following tables set forth certain information relating to the oil and natural gas reserves of the Corporation's properties and the present value of the estimated future net cash flow associated with such reserves as at December 31, 2013 which numbers may vary slightly from those presented in the GLJ Report, due to rounding. Also due to rounding, certain columns may not add exactly. The information set forth below is derived from the GLJ Report which reports have been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (“NI 51-101”). All evaluations and reviews of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. The estimated future net revenue from the production of disclosed oil and gas reserves does not represent the fair market value of the Corporation's reserves. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGLs and natural gas reserves may be greater than or less than the estimates provided herein.

In accordance with the requirements of NI 51-101, attached hereto are the following appendices:

Appendix A: Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor in Form 51-101F2.

Appendix B: Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3.

Appendix C: Definitions used for reserve categories in the GLJ Report.

The following tables summarize Terra Energy's oil and natural gas reserves as of December 31, 2013 based on a forecast price and cost assumptions:

**SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2013
FORECAST PRICES AND COSTS**

Reserves Category	Light And Medium Crude Oil		Heavy Oil		Natural Gas Liquids	
	Gross Before Royalty (mbbl)	Net After Royalty (mbbl)	Gross Before Royalty (mbbl)	Net After Royalty (mbbl)	Gross Before Royalty (mbbl)	Net After Royalty (mbbl)
Proved Producing	860	707	2	1	738	537
Developed Non-Producing	534	485	26	23	256	206
Proved Undeveloped	283	237	-	-	50	40
Total Proved	1,677	1,430	28	24	1,044	783
Probable	1,310	1,115	6	5	392	299
Total Proved Plus Probable	2,987	2,545	34	29	1,437	1,082

Reserves Category	Natural Gas		Coal Bed Methane		Total Oil Equivalent	
	Gross Before Royalty (mmcf)	Net After Royalty (mmcf)	Gross Before Royalty (mmcf)	Net After Royalty (mmcf)	Gross Before Royalty (mbbl)	Net After Royalty (mbbl)
Proved Producing	36,885	29,384	205	153	7,781	6,169
Developed Non-Producing	14,024	11,832	-	-	3,154	2,686

	Natural Gas		Coal Bed Methane		Total Oil Equivalent	
Proved Undeveloped	2,394	2,011	185	155	763	638
Total Proved	53,303	43,227	390	308	11,698	9,492
Probable	23,602	19,446	120	95	5,663	4,677
Total Proved Plus Probable	76,905	62,673	509	403	17,360	14,169

Note:

(1) Natural gas volumes include associated, non-associated and solution gas.

The following tables summarize the undiscounted value and the present value, discounted at 0%, 5%, 10%, 15% and 20%, of Terra Energy's estimated future net revenue based on forecast price and cost assumptions as of December 31, 2013:

**SUMMARY NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2013**

FORECAST PRICES AND COSTS

Reserves Category	Before Income Taxes Discounted at (% Year)					After Income Taxes Discounted at (% Year)					Unit Value Before Income Tax Discounted at 10%/ Year
	0	5	10	15	20	0	5	10	15	20	
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	\$/boe
Proved Producing	128,708	101,946	84,713	72,769	64,028	128,708	101,946	84,713	72,769	64,028	13.73
Developed Non-Producing	48,383	38,485	31,619	26,626	22,856	39,028	33,130	28,384	24,588	21,528	11.77
Undeveloped	13,366	10,264	8,001	6,315	5,034	9,947	7,781	6,177	4,959	4,013	12.54
Total Proved	190,457	150,695	124,332	105,710	91,918	177,682	142,857	119,274	102,316	89,568	13.10
Probable	108,231	72,001	51,290	38,298	29,581	80,550	53,561	38,177	28,545	22,085	10.97
Total Proved Plus Probable	298,688	222,696	175,622	144,008	121,500	258,232	196,418	157,451	130,860	111,653	12.39

TOTAL FUTURE NET REVENUE

(UNDISCOUNTED)

as of December 31, 2013

FORECAST PRICES AND COSTS

Reserves Category	Revenue (M\$)	Royalties (M\$)	Operating Costs (M\$)	Capital Development Costs (M\$)	Well Abandonment Cost (M\$)	Future Net Revenue Before Income Taxes (M\$)	Income Taxes (M\$)	Future Net Revenue After Income Taxes (M\$)
Proved Producing	349,203	61,739	153,342	1,675	3,740	128,708	-	128,708
Proved Developed Non-producing	146,652	19,776	66,413	10,074	2,006	48,383	9,355	39,028
Proved Undeveloped	45,461	7,216	14,399	10,190	289	13,366	3,419	9,947
Total Proved	541,316	88,731	234,155	21,939	6,035	190,457	12,775	177,682
Total Probable	307,915	49,089	121,604	27,319	1,673	108,231	27,681	80,550
Total Proved Plus Probable	849,231	137,820	355,759	49,257	7,708	298,688	40,455	258,232

**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 & ARTC (discounted at 10%/year) (M\$)	Unit Value Before Income Taxes (discounted at 10% year) (\$/BOE)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	46,839	21.98
	Heavy Oil (including by-products but excluding solution gas)	-	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	77,295	10.57
	Non-conventional Natural Gas	198	3.85
	Total	124,332	13.10
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	62,908	19.72
	Heavy Oil (including by-products but excluding solution gas)	-	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	112,458	10.31
	Non-conventional Natural Gas	256	3.82
	Total	175,622	12.39

RESERVE REPORT PRICING ASSUMPTIONS

Forecast Prices and Costs Employed by GLJ - December 31, 2013

GLJ employed the following pricing, exchange rate and inflation rate assumptions in estimating Terra Energy's reserves data using forecast prices and costs as of December 31, 2013.

FORECAST PRICES USED IN PREPARING RESERVES DATA

GLJ Petroleum Consultants

Crude Oil and Natural Gas Liquids

Price Forecast

Effective January 1, 2014

Year	WTI	Brent	Edmonton	WCS	Heavy	Cromer	Spec	Edmonton	Edmonton	Edmonton	Inflation	US/CAN
	Crude	Crude	Light	Medium	Crude	Medium						Ethane
	Oil	Oil	Crude	Crude	Crude	Crude	\$/bbl	\$/bbl	\$/bbl	Plus	%	Rate
	\$/bbl (1)	\$/bbl (2)	\$/bbl (3)	\$/bbl (4)	\$/bbl (5)	\$/bbl (6)						\$/US\$/CAN
Forecast												
2014 Q1	97.50	107.50	86.84	70.78	60.27	80.76	13.59	60.79	71.21	102.47	2.0	0.95
2014 Q2	97.50	107.50	92.11	75.07	65.64	85.66	12.93	55.26	71.84	103.16	2.0	0.95
2014 Q3	97.50	107.50	94.74	77.21	67.54	88.11	12.93	56.84	73.89	106.11	2.0	0.95
2014 Q4	97.50	107.50	97.37	79.36	69.54	90.55	13.59	58.42	75.95	109.05	2.0	0.95
2014 Full Year	97.50	107.50	92.76	75.60	65.72	86.27	13.26	57.83	73.22	105.20	2.0	0.95
2015	97.50	107.50	97.37	79.36	70.03	90.55	14.08	58.42	75.95	107.11	2.0	0.95
2016	97.50	105.00	100.00	81.50	72.85	93.00	14.89	60.00	78.00	107.00	2.0	0.95
2017	97.50	102.50	100.00	81.50	72.85	93.00	15.71	60.00	78.00	107.00	2.0	0.95
2018	97.50	102.50	100.00	81.50	72.85	93.00	16.53	60.00	78.00	107.00	2.0	0.95
2019	97.50	102.50	100.00	81.50	72.85	93.00	17.34	60.00	78.00	107.00	2.0	0.95
2020	98.54	102.50	100.77	82.13	73.42	93.71	17.77	60.46	78.60	107.82	2.0	0.95
2021	100.51	103.38	102.78	83.76	74.90	95.58	18.13	61.67	80.17	109.97	2.0	0.95
2022	102.52	105.45	104.83	85.44	76.42	97.49	18.52	62.90	81.77	112.17	2.0	0.95

Year	WTI Crude Oil \$US/bbl (1)	Brent Crude Oil \$US/bbl (2)	Edmonton Light Crude Oil \$C/bbl (3)	WCS Medium Crude Oil \$C/bbl (4)	Heavy Crude Oil \$C/bbl (5)	Cromer Medium Crude Oil \$C/bbl (6)	Spec Ethane \$C/bbl	Edmonton Propane \$C/bbl	Edmonton Butanes \$C/bbl	Edmonton Pentanes Plus \$C/bbl	Inflation %	US/CAN Exchange Rate \$US/\$CAN
2023	104.57	107.56	106.93	87.14	77.97	99.44	18.88	64.16	83.40	114.41	2.0	0.95
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	0.95

Notes:

- (1) West Texas Intermediate at Cushing Oklahoma
- (2) North Sea Brent Blend
- (3) Edmonton Light Sweet 40 degrees API, 0.3% sulphur
- (4) WCS steam quality at Hardisty Alberta
- (5) Heavy crude oil 12 degrees API at Hardisty Alberta
- (6) Midale Cromer crude oil 29 degrees API, 2.0% sulphur

FORECAST PRICES USED IN PREPARING RESERVES DATA**GLJ Petroleum Consultants****Natural Gas
Price Forecast****Effective January 1, 2014**

Year	NYMEX Futures Contract \$US/mmbtu	AECO Spot Price \$C/mmbtu	Alberta		Saskatchewan		British Columbia		
			Spot Plantgate \$C/mmbtu (1)	ARP Plantgate \$C/mmbtu	SaskEnergy \$C/mmbtu	Spot Plantgate \$C/mmbtu	Westcoast Station 2 \$C/mmbtu	Spot Plantgate \$C/mmbtu	
Forecast									
2014 Q1	4.35	4.12	3.90	3.90	4.00	4.04	4.02	3.82	
2014 Q2	4.15	3.93	3.72	3.72	3.82	3.85	3.73	3.54	
2014 Q3	4.15	3.93	3.72	3.72	3.82	3.85	3.73	3.54	
2014 Q4	4.35	4.12	3.90	3.90	4.00	4.04	4.02	3.82	
2014 Full Year	4.25	4.03	3.81	3.81	3.91	3.95	3.88	3.68	
2015	4.50	4.26	4.04	4.04	4.14	4.18	4.11	3.91	
2016	4.75	4.50	4.28	4.28	4.38	4.42	4.35	4.15	
2017	5.00	4.74	4.51	4.51	4.61	4.66	4.59	4.38	
2018	5.25	4.97	4.75	4.75	4.85	4.89	4.82	4.62	
2019	5.50	5.21	4.98	4.98	5.08	5.13	5.06	4.86	
2020	5.63	5.33	5.11	5.11	5.21	5.25	5.18	4.98	
2021	5.74	5.44	5.21	5.21	5.31	5.36	5.29	5.08	
2022	5.86	5.55	5.32	5.32	5.42	5.47	5.40	5.19	
2023	5.97	5.66	5.42	5.42	5.52	5.58	5.51	5.30	
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Note:

- (1) This forecast also applies to direct sales contracts and the Alberta gas reference price used in the crown royalty calculations.

Terra Energy's weighted average realized sales prices for the year ended December 31, 2013 were \$86.66/bbl for crude oil, \$3.21/mcf for natural gas and \$70.32/bbl for natural gas liquids.

RECONCILIATION OF CHANGES IN RESERVES

Reserves Reconciliation

The following table sets forth a reconciliation of Terra Energy's total working interest proved, probable and proved plus probable reserves as at December 31, 2013 against such reserves as at December 31, 2012 based on forecast price and cost assumptions.

FACTORS	Total Oil			Light and Medium Oil			Heavy Oil			Natural Gas Liquids		
	Proved (Mbbbl)	Probable (Mbbbl)	Proved + Probable (Mbbbl)	Proved (Mbbbl)	Probable (Mbbbl)	Proved + Probable (Mbbbl)	Proved (Mbbbl)	Probable (Mbbbl)	Proved + Probable (Mbbbl)	Proved (Mbbbl)	Probable (Mbbbl)	Proved + Probable (Mbbbl)
December 31, 2012	1,259	1,055	2,314	1,225	1,046	2,271	34	9	43	1,373	1,500	2,873
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions (1)	201	369	570	201	369	570	-	-	-	19	15	35
Infill Drilling (1)	81	36	117	81	36	117	-	-	-	3	1	4
Improved Recovery (1)	139	76	215	139	76	215	-	-	-	4	2	6
Technical Revisions	275	(84)	190	281	(81)	200	(6)	(3)	(9)	32	(61)	(29)
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	(132)	(110)	(241)	(132)	(110)	(241)	-	-	-	(273)	(1,056)	(1,329)
Economic Factors	22	(26)	(4)	22	(26)	(4)	-	-	-	(4)	(9)	(13)
Production	(140)	-	(140)	(140)	-	(140)	-	-	-	(109)	-	(109)
December 31, 2013	1,705	1,317	3,021	1,677	1,310	2,987	28	6	34	1,044	392	1,437

FACTORS	Total Gas			Conventional Natural Gas			Coal Bed Methane			BOE		
	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
December 31, 2012	63,758	64,546	128,303	63,259	64,378	127,636	499	168	667	13,258	13,313	26,571
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions (1)	307	1,036	1,343	307	1,036	1,343	-	-	-	271	557	828
Infill Drilling (1)	295	131	426	295	131	426	-	-	-	133	59	192
Improved Recovery (1)	609	205	813	609	205	813	-	-	-	244	112	357
Technical Revisions	7,426	(2,276)	5,151	7,462	(2,226)	5,235	(35)	(49)	(85)	1,544	(525)	1,019
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	(11,447)	(39,542)	(50,989)	(11,447)	(39,542)	(50,989)	-	-	-	(2,312)	(7,756)	(10,068)
Economic Factors	(327)	(378)	(705)	(317)	(379)	(696)	(10)	1	(9)	(37)	(98)	(135)
Production	(6,928)	-	(6,928)	(6,864)	-	(6,864)	(64)	-	(64)	(1,404)	-	(1,404)
December 31, 2013	53,693	23,722	77,415	53,303	23,602	76,905	390	120	509	11,698	5,663	17,360

Note:

(1) The above change categories correspond to standards set out in the Canadian Oil and Gas Evaluation Handbook. For reporting under NI 51-101, reserves additions under Infill Drilling, Improved Recovery and Extensions should be combined and reported as "Extensions and Improved Recovery".

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

The following discussion generally describes the basis on which Terra Energy attributes proved and probable undeveloped reserves and its plans for developing those undeveloped reserves.

Proved Undeveloped Reserves

Proved undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant capital expenditure is required to render them capable of production. There is a reasonable degree of certainty that the reserves will be recovered. It is possible that the actual remaining quantities recovered will exceed the estimated proved reserves. These reserves generally are those related to future drilling locations.

The total proved undeveloped reserves and the respective proportion of the Corporation are located in the following properties: Boudreau/Red Creek, 34%, Dimsdale 19%, Sunrise/Tower 18% and Eagle/Stoddart 16%. Terra Energy has identified total of 17 infill development and extension drilling locations: at Boudreau/Red Creek 3 Doig and 2 Baldonnel drilling locations, Dimsdale one Charlie Lake drilling location, Sunrise/Tower 4 Doig, 2 Halfway and 2 Taylor Flats drilling locations and Eagle/Stoddart 3 Belloy drilling locations.

The following table sets forth the volumes of gross proved undeveloped reserves that were first attributed in each of Terra Energy's three most recent financial years and before that, in aggregate:

	Light and Medium Crude Oil		Heavy Crude Oil		Natural Gas		Natural Gas Liquids	
	1st Attributed	Cumulative at Year End	1st Attributed	Cumulative at Year End	1st Attributed	Cumulative at Year End	1st Attributed	Cumulative at Year End
Dec. 31	(mboe)	(mboe)	(mboe)	(mboe)	(mmcf)	(mmcf)	(mboe)	(mboe)
Prior to 2011	3	3	-	-	16,991	16,991	337	337
2011	74	74	-	-	396	15,435	-	307
2012	-	74	-	-	-	7,749	-	193
2013	282	283	-	-	602	2,394	22	50

	Synthetic Crude Oil		Bitumen		Coal Bed Methane		Oil Equivalent	
	1st Attributed	Cumulative at Year End	1st Attributed	Cumulative at Year End	1st Attributed	Cumulative at Year End	1st Attributed	Cumulative at Year End
Dec. 31	(mboe)	(mboe)	(mboe)	(mboe)	(mmcf)	(mmcf)	(mboe)	(mboe)
Prior to 2011	-	-	-	-	187	187	3,203	3,203
2011	-	-	-	-	-	591	140	3,052
2012	-	-	-	-	-	185	-	1,589
2013	-	-	-	-	-	185	405	763

Probable Undeveloped Reserves

Probable undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant capital expenditure is required to render them capable of production. Probable reserves are less certain to be recovered than proved reserves. The actual remaining quantities recovered may be greater or less than the sum of the estimated proved plus probable reserves. These reserves generally are those related to future drilling locations.

The majority of Terra Energy's probable undeveloped reserves are related to drilling locations identified by GLJ and Terra Energy as locations which are highly prospective for natural gas and/or crude oil discoveries.

The probable undeveloped reserves and their respective proportions of the Corporation are associated with the following properties: Boudreau/Red Creek, 28%, Dimsdale 21%, Sunrise/Tower 14% and Eagle/Stoddart 19%. The probable undeveloped reserves are associated with 17 drilling locations listed above with the proven undeveloped reserves.

The remaining probable undeveloped reserves relate to reserves associated with small working interest drilling locations, producing wells which may, depending on economics and actual well production results, produce additional reserves above and beyond the existing proved reserves.

The following table sets forth the volumes of probable undeveloped reserves that were first attributed in each of Terra Energy's three most recent financial years and, before that, in aggregate:

	Light and Medium Crude Oil		Heavy Crude Oil		Natural Gas		Natural Gas Liquids	
	1st Attributed	Cumulative at Year End	1st Attributed	Cumulative at Year End	1st Attributed	Cumulative at Year End	1st Attributed	Cumulative at Year End
Dec. 31	(mboe)	(mboe)	(mboe)	(mboe)	(mmcf)	(mmcf)	(mboe)	(mboe)
Prior to 2011	419	419	-	-	31,949	31,949	743	743
2011	262	660	-	-	30,584	58,424	816	1,460
2012	-	654	-	-	-	44,064	-	1,120
2013	405	845	-	-	1,167	6,617	17	104

	Synthetic Crude Oil		Bitumen		Coal Bed Methane		Oil Equivalent	
	1st Attributed	Cumulative at Year End	1st Attributed	Cumulative at Year End	1st Attributed	Cumulative at Year End	1st Attributed	Cumulative at Year End
Dec. 31	(mboe)	(mboe)	(mboe)	(mboe)	(mmcf)	(mmcf)	(mboe)	(mboe)
Prior to 2011	-	-	-	-	79	79	6,500	6,500
2011	-	-	-	-	-	149	6,175	11,882
2012	-	-	-	-	-	74	-	9,130
2013	-	-	-	-	-	69	616	2,064

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, commodity prices and economic conditions. Terra Energy's reserves are evaluated by GLJ which is an independent engineering firm.

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, commodity 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. Terra Energy's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

Future Development Costs

The following table outlines development costs deducted in the estimation of future net revenue attributable to proved reserves (using forecast prices and costs) and proved plus probable reserves (using forecast prices and costs) to those properties evaluated in the GLJ Report.

	Future Development Costs	
	Proved Reserves (M\$)	Proved Plus Probable Reserves (M\$)
2014	9,064	16,148
2015	9,015	21,677
2016	526	6,313
2017	426	611
2018	1,118	449
Remaining Years	1,788	4,059
Total Undiscounted	21,939	49,257
Total Discounted at 10% per year	18,602	41,512

The Corporation's Board of Directors has approved approximately \$14.3 million for its 2014 capital program to fund its exploration and development activities. Future development costs will be funded through a combination of cash flow, asset sale proceeds, debt and/or equity. See "*GENERAL DEVELOPMENT OF THE BUSINESS – 2013*"; and "*Subsequent Events*".

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

The following discussion outlines the Corporation's significant properties:

Boudreau/Red Creek (BC)

This area is approximately 30 km west of Fort St. John and is comprised of 55 sections of land in which the Corporation has an interest. Terra Energy produced an average of 316 boe/d (14 boe/d oil, 1.69 mmcf/d gas and 20 boe/d NGL's) over the 2013 calendar year. The Corporation has 47 wells with an average WI of 97% in the property. The GLJ report attributed 349 mboe proved producing and 2,776 mboe proved and probable reserves to the area.

Sunrise/Tower (BC)

This area is approximately 25 km southeast of Fort St. John. The property is comprised of 10 sections of land in which the Corporation has interest. Production for the 2013 year averaged 798 boe/d (4.18 mmcf/d gas and 101 boe/d NGL's). Terra Energy has an interest in 33 wells in the area with an average working interest of 79 %. The GLJ report attributed 1,695 mboe proved producing and 3,899 mboe proved and probable reserves.

Monais/Wilder (BC)

The Monais/Wilder area is located some 20 km southwest of Fort St. John and extends over several kilometers. Terra Energy has interests in 98 sections along the property trend. Production for 2013 averaged 802 boe/d (4.54 mmcf/d gas, 40 boepd NGL's and 5 boe/d oil). There are 26 wells in which Terra has an average working interest of 72 %. The GLJ report attributed 1,567 mboe proved producing and 2,648 mboe proved and probable reserves.

Stoddart/Eagle (BC)

The Stoddart/Eagle property is 13 km from Fort St. John and extends to the west/northwest. There are 52 sections of land in which the Corporation has interests. Average 2013 production was 322 boe/d (97 boe/d oil, 1.12 mmcf/d gas and 39 boe/d NGL's). The Corporation has an average working interest of 67 % in 69 wells. The GLJ report attributed 922 mboe proved producing and 2,049 mboe proved and probable reserves.

Square Creek (Alberta)

The property of Square Creek is located approximately 130 km northeast of Fort St. John in the province of Alberta. The area is remote and the Corporation has interest in 16 sections of land. The 2013 average production for the property was 708 boe/d (4.25 mmcf/d gas). Terra Energy has an average working interest of 100 % in 12 wells. The GLJ report attributed 1,186 mboe of proved producing and 1,764 mboe proved and probable reserves.

The following discussion outlines the Corporation's, plants, facilities and installations:

Boudreau (B.C.)

The Boudreau 14-13-84-21 W6M sour oil / gas facility is located approximately 25 km west of Fort St. John and was constructed by Terra Energy in the 4th quarter of 2004. The Corporation owns 100% of this facility. The Boudreau facility has compression, dehydration, oil / water separation and water disposal handling. The oil is trucked from the facility and the gas is compressed and delivered to the Spectra raw gas gathering system for processing at the Spectra McMahon Gas Plant. In 2006, Terra Energy constructed a "line-loop" pipeline connecting the Corporation's underutilized Red Creek facility to the new natural gas discovery wells in Boudreau. With the completion of the pipeline, the majority of Terra Energy's Boudreau production is processed at the Red Creek facility.

Eagle (B.C.)

Terra Energy operates and has a 40.16% ownership interest in a 2.9 mmcf/d gas facility located at 6-19-85-18 W6M in the Eagle area. The facility consists of desiccant dehydration and compression facilities. The facility is located approximately 13 km north of Fort St. John.

Red Creek (B.C.)

The Red Creek 3-10-85-21 W6M facility is located approximately 35 km west of Fort St. John and is equipped with compression, dehydration, oil separation and water injection. In 2005, a new 4 inch pipeline was constructed to tie-in two new Baldonnel development wells to the underutilized Red Creek facility. Additional drilling added four additional Baldonnel wells. In December 2005, a new 815 horsepower compressor was added to handle this new and future production from the area south of Red Creek. The compressor is capable of handling 8 mmcf/d and with additional pipeline capacity up to 10 mmcf/d. The existing low pressure compressor continues to handle the solution gas and low pressure gas from the Red Creek field. In September 2007, a 19.5 km gathering line connecting the East Boudreau gas field to Red Creek was commissioned. The Corporation owns 100% of this facility.

Stoddart (B.C.)

The Stoddart Facility at 14-26-85-20 W5M is located approximately 25 km northwest of Fort St. John. The facility consists of an oil battery and gas compression. The battery is pipeline connected to an oil pipeline and the natural gas is delivered to the Spectra raw gas gathering system for delivery to the Spectra McMahon Gas facility.

Tower (B.C.)

The Tower 9-28-81-17 W6M sour dehydration and compression facility is located approximately 24 km southeast of Fort St. John and was constructed by Terra Energy in the 4th quarter of 2007. The Corporation owns 100% of this facility. Initially, four wells (eight productive zones) were tied into the facility. Additional wells were tied in from the North Eight Mile and Sunrise areas in 2008 with completion of a 25.4 km 8 inch gathering pipeline.

The Tower facility had initially installed capacity of 14 mmcf/d and was enlarged to 20 mmcf/d with the addition of a second compressor in November 2008. The facility has compression, dehydration, separation facilities and tanks for field condensate and water. The facility is connected to the Spectra "South Peace Pipeline" and delivers gas to the Spectra McMahon Gas facility.

The Tower facility was connected to the Septimus and Wilder fields via a six inch 38 km pipeline. Subsequent to year end 2011, this pipeline was sold to an industry partner. The pipeline was not in use at the time of the sale.

The Sunrise portion of the 8 inch gathering pipeline is also connected to a third party gathering system and facility located at West Doe. Approximately 3.25 mmcf/d of firm capacity sour processing is contracted at the West Doe facility.

Wilder (B.C.)

The Wilder 10-34-82-20 W6M gas facility is located 20 km southeast of Fort St. John and is equipped with compression and dehydration. The Wilder facility has capacity of approximately 10 mmcf/d and is owned 100% by the Corporation. This facility processes Terra Energy owned production plus third party gas and is in a key area for additional third party processing from the Montney resource play.

Stoddart 4-24 and North Pine 11-2 (B.C.)

Terra Energy acquired two facilities in the Stoddart/North Pine area in 2009 as part of the Peace River Arch Assets. The Stoddart 4-24 facility has a 200 hp screw booster compressor, a 768 hp recip compressor and dehydration for processing of gas for sales to Spectra's raw gas gathering system. The North Pine 11-2 facility has a 1,545 hp recip compressor and dehydration for processing of gas for sales to Spectra's raw gas gathering system. The Corporation owns 94.7% of the Stoddart 4-24 facility, 41.9% of the North Pine 11-2 facility and operates both on behalf of the working interest partners.

North Boundary/Hill (AB)

The North Boundary 10-19-86-11W6M gas facility is located 72 km northeast of Fort St. John and is equipped with an amine and dehydration facility. In the fall of 2011, a 400 hp compressor was added to the facility to maintain production through the facility at design rates. The facility has an approximate capacity of 3 mmcf/d and is licensed for a maximum of 1 tonne/day of sulfur

emissions. The facility is connected to an existing third party facility for dew point control and sales metering to the Nova Gas Transmission system. The Corporation owns 65.625% of the facility and operates it on behalf of the working interest partners. This facility was acquired in 2009 as part of the Peace River Arch Assets.

Worsley (AB)

The Worsley 16-36-86-10 W6M sweet gas facility is located 90 km northeast of Fort St. John and is equipped with a 6 mmcf/d compressor and a 5 mmcf/d refrigeration unit for gas treatment and sales to Nova Gas Transmission. There is a second decommissioned 7 mmcf/d refrigeration package located on site. This facility processes both owned production and some third party gas and is owned 100% by the Corporation. This facility was acquired in 2009 as part of the Peace River Arch Assets.

Cecil Battery (AB)

The Cecil 8-6-85-8 W6M battery is located 100 km east of Fort St. John and is equipped with 2,000 bbls of oil separation and storage capacity, a 3,000 bbl/d water injection system and a 100 hp solution gas compressor. Solution gas is gathered to the Devon operated 16-4-85-8 W6M Cecil facility for further processing. The Corporation owns 90% of the facility and operates it on behalf of the working interest partners. This facility was acquired in 2009 as part of the Peace River Arch Assets.

Dimsdale (AB)

The Dimsdale facility is located 3 km west of Grande Prairie, Alberta and is equipped with separation and metering facilities and compression. The gas is tied into the Wembley gas plant where the gas is processed and shipped to sales. This infrastructure will be utilized with production obtained from the two new wells Terra Energy drilled in 2005.

Square Creek (AB)

The Square Creek 16-16-93-9 W6M facility is located approximately 130 km northeast of Fort St. John and is equipped with compression, dehydration, storage tanks and an operations camp. Access to the facility is by helicopter for normal operations and by ice road during the winter months only. The Corporation owns 100% of this facility. The facility was constructed in 2008 and was purchased from Fortress Energy Inc. in September 2010. Gas from the facility is gathered through a 50 km Altagas owned and operated gathering line to the Altagas Clear Prairie 7-33-90-12 W6M gas plant for dew point treating and sales metering to the Nova Gas Transmission system. The approximate capacity of this facility is 8-10 mmcf/d.

Hamelin Creek (AB)

Sour field compressor facility located at 12-33-80-6W6 was constructed in 2004 and is licensed for 2% H₂S. The facility has an 810 HP two stage compressor with inlet separators. Produced water is handled through the facility's 30HP water injection pump into dedicated disposal wells. Hydrocarbon liquids are recombined with the gas and sent down to the Spectra facility at Gordondale 11-26-79-8W6. Terra has an 80% working interest.

Wells

As at December 31, 2013, the Corporation had an interest in 241 gross (138net) producing and 360 gross (228net) non-producing oil, natural gas and other wells as follows:

Wells	PRODUCING				NON-PRODUCING					
	Oil		Natural Gas		Oil		Natural Gas		Other	
	Gross (1)	Net (2)	Gross	Net	Gross	Net	Gross	Net	Gross	Net
B.C.	10	8	120	72	5	5	179	110	4	3
Alberta	26	12	85	46	3	1	157	100	8	8
Sask.	0	-	-	-	4	1	-	-	-	-
Total Wells	36	20	205	118	12	7	336	210	12	11

Notes:

- (1) "Gross" wells means the number of wells in which Terra Energy has a working interest.
- (2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Terra Energy's percentage working interest therein.

Properties with No Attributed Reserves

The following table sets forth the gross and net acres of unproved properties held by the Corporation as at December 31, 2013 and the net area of unproved property for which the Corporation expects its rights to explore, develop and exploit to expire during the next year:

Location	UNPROVED PROPERTIES (acres)		Net Area to Expire by December 31, 2014
	Gross (1)	Net (2)	
Alberta	206,191	159,764	5,901
Saskatchewan	406	40	-
British Columbia	256,095	152,117	21,652
TOTAL	462,693	311,921	27,553

Notes:

- (1) "Gross Acres" are the total acres in which Terra Energy has or had an interest.
- (2) "Net Acres" is the aggregate of the total acres in which Terra Energy has or had an interest multiplied by Terra Energy's working interest percentage held therein.

Where Terra Energy holds an interest in two different formations under the same surface area pursuant to separate leases, the gross/net acreages for both leases is included. If only one lease but more than one split, the split with largest gross/net acreage is included.

There are no costs or work commitments associated with Terra Energy's non-producing properties except for ongoing Crown lease commitments.

The undeveloped land holdings of the Corporation were evaluated as at December 31, 2013 by Seaton-Jordan & Associates Ltd. ("**Seaton-Jordan**"). The estimated value of Terra Energy's net undeveloped land holdings is approximately \$33.4 million as at December 31, 2013.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

There are several economic factors and significant uncertainties that may affect the anticipated development of Terra Energy's properties with no attributed reserves. Terra Energy will be required to make substantial capital expenditures in order to prove, exploit, develop and produce oil and natural gas from these properties in the future. Development of these properties to commercial status may require additional debt or equity financing. Failure to obtain such financing on a timely basis or on terms acceptable to Terra Energy may cause Terra Energy to forfeit its interest in certain properties, miss certain opportunities and reduce or terminate its operations. The inability of Terra Energy to access sufficient capital for its exploration and development purposes could have a material adverse effect on Terra Energy's ability to execute its business strategy to develop these prospects. For further information, see "Risk Factors".

Forward Contracts

Terra Energy may use certain financial instruments to hedge its exposure to commodity price fluctuations on a portion of its crude oil and natural gas production. At December 31, 2013, the Corporation had the following derivative commodity contracts outstanding.

Natural Gas Contract Type	Price	Volumes per Day	Contract Term
Financial	\$3.25 CAD	14,000 GJ	November 1, 2013 to March 31, 2014

Subsequent to December 31, 2013, the Corporation entered into the following natural gas derivative contracts:

Natural Gas Contract type	Price	Volumes per day	Contract term
Fixed Price Swap	Sell \$3.610	1,000 GJ	April 1, 2014 to October 31, 2014
Fixed Price Swap	Sell \$3.765	500 GJ	April 1, 2014 to October 31, 2014
Fixed Price Swap	Sell \$4.185	500 GJ	April 1, 2014 to October 31, 2014

Natural Gas Contract type	Price	Volumes per day	Contract term
Fixed Price Swap	Sell \$4.210	500 GJ	April 1, 2014 to October 31, 2014
Fixed Price Swap	Sell \$4.220	500 GJ	April 1, 2014 to October 31, 2014
Fixed Price Swap	Sell \$4.270	500 GJ	April 1, 2014 to October 31, 2014
Fixed Price Swap	Sell \$4.010	2,000 GJ	April 1, 2014 to October 31, 2014
Fixed Price Swap	Sell \$4.050	1,000 GJ	April 1, 2014 to October 31, 2014
Fixed Price Swap	Sell \$4.345	500 GJ	April 1, 2014 to October 31, 2014
Fixed Price Swap	Sell \$4.120	500 GJ	April 1, 2014 to October 31, 2014
Fixed Price Swap	Sell \$4.380	500 GJ	May 1, 2014 to October 31, 2014

Additional Information Concerning Abandonment and Reclamation Costs

Terra Energy estimates well abandonment and reclamation costs for surface leases, wells and facilities based on its previous experience, current regulations, costs, technology and industry standards area by area. Such costs are included in the GLJ Report as deductions in arriving at future net revenue. The expected total abandonment costs for 601 gross (365net) wells (including producing, non-producing and service wells) and for 20 gross (16 net) facilities are summarized in the net of estimated salvage value calculated without discount and using a discount rate of 10% is as follows:

Reserves	Forecast (M\$) Pricing			
	Proved NPV 0%	Proved NPV 10%	Proved Plus Probable NPV 0%	Proved Plus Probable NPV 10%
Wells with reserves assigned	6,035	2,641	7,708	2,679
Wells and Facilities with no reserves assigned	15,676	10,170	15,676	10,170
Total abandonment and reclamation cost provision (1)(2)	21,711	12,811	23,475	12,849
Portion forecast to be paid during the next three years	1,149	1,065	959	889

Notes:

- (1) Abandonment and disconnect costs were estimated by GLJ and are included in the GLJ Report for wells assigned reserves.
- (2) The Corporation has estimated the timing and costs associated with the abandonment and reclamation for wells with no reserves assigned. These costs were not included in the GLJ Report.

Income Tax Horizon

At December 31, 2013, Terra Energy had estimated income tax pools of approximately \$124 million available to reduce future taxable income. Terra Energy does not expect to incur material current income taxes for the year ending December 31, 2014.

Costs Incurred

The following table summarizes Terra Energy's property acquisition costs, exploration costs and development costs (before property dispositions and drilling royalty credits) incurred during the financial year ended December 31, 2013.

Nature of Cost(m\$)	Proved	Unproved	Total
Exploration	-	-	-
Development	1,732	-	1,732
Undeveloped Land	-	512	512
Geological / Geotechnical Facilities	2	-	2
Other Assets	-	6	6
Total Capital Expenditure	1,734	512	2,252
Net Property Acquisitions			-
Net Property Disposition			(55,274)
Total Capital Expenditure			(53,022)

Exploration and Development Activities

Terra Energy did not drill any exploration and development wells during the financial year ended December 31, 2013.

Anticipated 2014 exploration and development expenditures will be directed towards conventional oil and gas liquids and will be primarily focused on tie-in of existing wells and recompletion projects.

Production Estimates

The following table discloses the volume of Terra Energy's production estimated before the deduction of royalties for the first year of the gross proved reserves and gross probable reserves estimates reported in the GLJ Report effective December 31, 2013, based on forecast prices and costs. The Corporation sold its interests in the primary Shale Gas property in 2013. The coal bed methane properties in Central Alberta are less than 1% of the Corporation's total natural gas reserves:

	Light and Medium Crude Oil (bbl/d)	Heavy Oil (bbl/d)	Natural Gas (mcf/d)	Coal Bed Methane (mcf/d)	Shale Gas (mcf/d)	Natural Gas Liquids (bbl/d)
Proved						
Developed Producing	386	1	17,531	154	-	265
Developed Non-Producing	199	5	3,299	-	-	59
Proved Undeveloped	32	-	52	-	-	5
Total Proved	617	5	20,882	154	-	329
Probable	106	-	1,210	1	-	12
Total Proved Plus Probable	723	5	22,092	155	-	341

Production History

The following table summarizes Terra Energy's average gross daily sales production volumes for the periods indicated.

	Year Ended December 31, 2013	2013			
		Q4 Oct. - Dec.	Q3 July - Sept.	Q2 April - June	Q1 Jan. - March
Oil (bbl/d)	385	378	389	367	407
Natural Gas Liquids (bbl/d)	290	183	218	318	446
Natural Gas (mcf/d)	19,188	17,684	19,078	18,338	21,698
Total (boe/d)	3,873	3,508	3,786	3,741	4,469

Netback History

The following table sets forth information respecting average net product prices received, royalties paid, operating expenses and netbacks received by the Corporation in respect of the Corporation's production of crude oil and natural gas for the periods indicated.

	Year Ended December 31, 2013	2013			
		Q4 Oct. - Dec.	Q3 July - Sept.	Q2 April - June	Q1 Jan. - March
Selling Prices					
Oil (\$/bbl)	86.66	79.43	99.16	84.31	83.46
Natural Gas (\$/mcf)	3.21	3.44	2.62	3.75	3.09
Natural Gas Liquids (\$/bbl)	70.32	76.62	103.71	61.36	57.37
Royalties					
Oil (\$/bbl)	19.82	18.19	22.67	22.01	16.61
Natural Gas (\$/mcf)	0.27	0.09	0.25	0.19	0.52
Natural Gas Liquids (\$/bbl)	23.87	49.28	30.18	18.83	13.18
Production Expenses (1)					

	Year Ended December 31, 2013	2013			
		Q4 Oct. - Dec.	Q3 July - Sept.	Q2 April - June	Q1 Jan. - March
Oil (\$/bbl)	14.98	16.42	14.84	16.88	12.33
Natural Gas (\$/mcf)	2.50	2.74	2.47	2.81	2.06
Natural Gas Liquids (\$/bbl)	14.98	16.42	14.84	16.88	12.33
Field Netbacks					
Oil (\$/bbl)	51.86	44.82	61.64	45.43	54.52
Natural Gas (\$/mcf)	0.44	0.62	(0.11)	0.75	0.52
Natural Gas Liquids (\$/bbl)	31.46	10.92	58.68	25.65	31.85

Note:

(1) Operating expenses include mineral and surface lease rentals, property taxes and expenses related to the operation and maintenance of wells, production facilities and gathering systems.

Production Volume by Field

The following table discloses for each significant field, and in total, Terra Energy's sales production volumes for the financial year ended December 31, 2013 for each product type.

Field	Light and Medium Crude Oil	Natural Gas	Natural Gas Liquids	BOE	%
	(bbls/d)	(mcf/d)	(bbls/d)	(boe/d)	
Boudreau & Red Creek, British Columbia	14	1,690	20	316	8%
Sunrise & Tower, British Columbia	-	4,182	101	798	21%
Monias & Wilder, British Columbia	5	4,541	40	802	21%
Eagle & Stoddart, British Columbia	97	1,115	39	323	8%
Square Creek, Alberta	-	4,429	-	708	18%
Other	269	3,231	93	929	24%
Total	385	19,188	293	3,876	100%

RISK FACTORS

The business of exploring for, developing and producing oil and natural gas reserves is inherently risky. Oil and natural gas operations involve many risks which even a combination of experience and knowledge and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by Terra Energy.

Forward-Looking Statements and Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking statements and information. By its nature, forward-looking statements and information involve numerous assumptions, known and unknown risk 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 related to forward-looking statements and information are found under the heading "Forward-Looking Statements" in this Annual Information Form.

Uncertain Discovery of Viable Commercial Prospects

The Corporation's future success may be dependent upon its ability to economically locate commercially viable oil or gas deposits. The Corporation can make no representations, warranties or guaranties that it will be able to consistently identify viable prospects, or that such prospects will be commercially exploitable. An inability of the Corporation to consistently identify and exploit commercially viable hydrocarbon deposits would have a material and adverse effect on the Corporation's business and financial position. Exploratory drilling is subject to numerous risks, including the risk that no commercially productive oil and gas reservoirs will be encountered. The cost of drilling, completing and operating wells is often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including unexpected formation and drilling conditions, pressure or other irregularities in formations, blowouts, equipment failures or accidents, as well as weather conditions, compliance

with governmental requirements and/or shortages or delays in the delivery of equipment. The inability to successfully locate and drill wells that will economically produce commercial quantities of oil and gas could have a material adverse effect on the Corporation's business and financial position. The Corporation's properties are in various stages of exploration and development. Whether the Corporation ultimately drills a property may depend on a number of factors including funding, the receipt of additional seismic data or reprocessing of existing data, material changes in oil or gas prices, the costs and availability of drilling equipment, success or failure of wells drilled in similar formations or which would use the same production facilities, changes in estimates of costs to drill or complete wells, the Corporation's ability to attract industry partners to acquire a portion of its working interest to reduce exposure to drilling and completion costs, decisions of the Corporation's joint working interest owners, and/or restrictions under provincial regulators.

Volatility of Oil and Natural Gas Contracts

The ultimate profitability, cash flow and future growth of the Corporation will be affected by changes in prevailing oil and gas prices. Oil and gas prices have been subject to wide fluctuations in recent years in response to changes in the supply and demand for oil and natural gas, market uncertainty, competition, regulatory developments and other factors which are beyond the control of the Corporation. It is impossible to predict future oil and natural gas price movements with any certainty. An extended or substantial decline in oil and gas prices would have a material adverse effect on: (i) the Corporation's access to capital; and (ii) the Corporation's financial position and results of operations.

Exploration, Development and Production Risks

Oil and natural gas exploration involves a high degree of risk and there is no assurance that expenditures made on exploration by Terra Energy will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

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

Prices, Markets and Marketing of Crude Oil and Natural Gas

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond the control of Terra Energy. World prices for oil and natural gas have fluctuated widely in recent years. Any material decline in prices will result in a reduction of net production revenue. Certain wells or other projects may become uneconomic as a result of a decline in world oil prices and natural gas prices, leading to a reduction in the future volume of Terra Energy's oil and gas production. Terra Energy might also elect not to produce from certain wells at lower prices. All these factors could result in a material decrease in Terra Energy's future net production revenue, causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to Terra Energy will be in part determined by the borrowing base of Terra Energy. A sustained material decline in prices from historical average prices could reduce Terra Energy's future borrowing base, therefore reducing the bank credit available to Terra Energy, and could require that a portion of any existing bank debt of Terra Energy be repaid.

In addition to establishing markets for its oil and natural gas, Terra Energy must also successfully market its oil and natural gas to prospective buyers. The marketability and price of oil and natural gas which may be acquired or discovered by Terra Energy will be affected by numerous factors beyond its control. Terra Energy will be affected by the differential between the price paid by refiners for light quality oil and the grades of oil produced by Terra Energy. The ability of Terra Energy to market natural gas may depend upon its ability to acquire space on pipelines which deliver natural gas to commercial markets. Terra Energy will also likely be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and related to operational problems with such pipelines and facilities and extensive government regulation relating to price, taxes,

royalties, land tenure, allowable production, the export of oil and natural gas and the management of other aspects of the oil and natural gas business. Terra Energy has limited direct experience in the marketing of oil and natural gas.

Geo-Political Risks

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

In addition, Terra Energy's expected oil and natural gas properties, wells and facilities could be subject to a terrorist attack. As the oil and gas industry in Canada is a key supplier of energy to the United States, certain terrorist groups may target Canadian oil and gas properties, wells and facilities in an effort to choke the United States economy. If any of Terra Energy's properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on Terra Energy. Terra Energy does not have insurance to protect against the risk from terrorism.

Global Economic Conditions

Market events and conditions, including disruptions in the international credit markets and other financial systems, the deterioration of global economic conditions, and recent natural disasters have caused significant volatility to commodity prices. These events and conditions have caused a loss of confidence in the broader U.S. and global credit and financial markets and which has resulted in the collapse of, and government intervention in, major banks, financial institutions and insurers and thereby creating 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 continue to cause uncertainty in both the credit and capital markets. These factors may continue to negatively impact corporate valuations and may impact the performance of the global economy going forward.

Petroleum and natural gas prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing global credit and liquidity concerns as well, due to recent geo-political uncertainty in North Africa and the Middle East.

Capital Markets

Continued global economic volatility may result in Terra Energy, along with all other oil and gas entities, to have restricted access to capital, bank debt and equity, and could face increased borrowing costs. Although Terra Energy's business and asset base have not changed, the lending capacity of all financial institutions has diminished and risk premiums have increased. As future capital expenditures will be financed out of funds generated from operations, borrowings and possible future equity sales, Terra Energy's ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and Terra Energy's securities in particular.

To the extent that external sources of capital become limited or unavailable or available only on onerous terms, Terra Energy'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 materially and adversely affected as a result.

Based on current funds available, pending asset sales and expected funds generated from operations, Terra Energy believes it has sufficient funds available to fund its projected capital expenditures. However, if funds generated from operations are lower than expected or capital costs for these projects exceed current estimates, or if Terra Energy incurs major unanticipated expenses related to development or maintenance of its existing properties, it may be required to seek additional capital to maintain its capital expenditures at planned levels. Failure to obtain any financing necessary for Terra Energy's capital expenditure plans may result in a delay in development or production on Terra Energy's properties.

Royalty Regime

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by governmental regulation and are generally calculated as a

percentage of the value of the gross production, and the rate of royalties payable generally depends in part on well productivity, geographical location, field discovery data and the type or quality of the petroleum product produced.

The royalty regime in British Columbia, Alberta and any other jurisdictions in which the Corporation's oil and natural gas assets are located may be subject to further review and changes which could adversely impact Terra Energy's financial condition and operations.

Substantial Capital Requirements; Liquidity

Terra Energy anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If Terra Energy's future revenues or reserves decline, Terra Energy may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to Terra Energy. Moreover, future activities may require Terra Energy to alter its capitalization significantly. The inability of Terra Energy to access sufficient capital for its operations could have material adverse effect on Terra Energy's financial condition, results of operations or prospects.

Competition

The Corporation engages in the highly competitive industry of exploration for and production of oil and gas. The Corporation competes directly and indirectly with major and independent oil and gas companies in its exploration for and development of desirable oil and gas properties. Many companies and individuals are engaged in the business of acquiring interests in and developing oil and gas properties in Canada, and the industry is not dominated by any single competitor or a small number of competitors. Many of such competitors have substantially greater financial, technical, sales, marketing and other resources, as well as greater historical market acceptance than does the Corporation. The Corporation will compete with numerous industry participants for the acquisition of land and rights to prospects, and for the equipment and labor required to operate and develop such prospects. Competition could materially and adversely affect the Corporation's business, operating results and financial condition. Such competitive disadvantages could adversely affect the Corporation's ability to participate in projects with favorable rates of return.

Shortage of Supplies and Equipment

The Corporation's ability to conduct operations in a timely and cost effective manner is subject to the availability of natural gas and crude oil field supplies, rigs, equipment and service crews. Although none are expected currently, any shortage of certain types of supplies and equipment could result in delays in our operations as well as in higher operating and capital costs.

Interruption from Severe Weather

The Corporation's operations are conducted principally in the central region of Alberta, northeastern British Columbia and Saskatchewan. The weather in these areas can be extreme and can cause interruption or delays in our drilling and construction operations.

Dependence on Third-Party Pipelines and Gathering and Processing Facilities

Substantially all of Terra Energy's sales of natural gas production are through deliveries to local third-party gathering systems to processing plants. In addition, the Corporation relies on access to interprovincial pipelines for the sale and distribution of substantially all of our natural gas. As a result, a curtailment of our sale of natural gas by pipelines or by third-party gathering systems, an impairment of our ability to transport natural gas on interprovincial pipelines or a material increase in the rates charged to us for the transportation of natural gas by reason of a change in federal or provincial regulations or for any other reason, could have a material adverse effect upon us. In such event, we would have to obtain other transportation arrangements. There can be no assurance that we would have economical transportation alternatives or that it would be feasible for us to construct pipelines. In the event such circumstances were to occur, our netbacks from the affected wells would be suspended until, and if, such circumstances could be resolved.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties 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 requirement or as a result of unexpected events. A discontinuation or decrease of operations could materially adversely affect the Corporation's ability to process its production and deliver the same for sale.

Operating Hazards and Uninsured Risks

The oil and gas business involves a variety of operating risks, including fire, explosion, pipe failure, casing collapse, abnormally pressured formations, adverse weather conditions, governmental and political actions, premature reservoir declines and environmental hazards such as oil spills, gas leaks and discharges of toxic gases. The occurrence of any of these events with respect to any property operated or owned (in whole or in part) by us could have a material adverse impact on us. The Corporation and the operators of our properties, maintain insurance in accordance with customary industry practices and in amounts that we believe to be reasonable. However, insurance coverage is not always economically feasible and is not obtained to cover all types of operational risks. The occurrence of a significant event that is not insured or insured fully could have a material adverse effect on our financial condition.

Restoration, Safety and Environmental Risks

Our operations are in Alberta, British Columbia and Saskatchewan. Certain laws and regulations exist that require companies engaged in petroleum activities to obtain necessary safety and environmental permits to operate. Such legislation may restrict or delay us from conducting operations in certain geographical areas. Further, such laws and regulations may impose liabilities on us for remedial and clean-up costs, personal injuries related to safety and environmental damages, such liabilities collectively referred to as “asset retirement obligations”.

Hydraulic Fracturing

Concern has been expressed over the potential environmental impact of hydraulic fracturing operations, including water aquifer contamination and other qualitative and quantitative effects on water resources as large quantities of water are used and injected fluids either remain underground or flow back to the surface to be collected, treated and disposed of. Regulatory authorities in certain jurisdictions have announced initiatives in response to such concerns. Federal, provincial and local legislative and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities could result in increased costs, additional operating restrictions or delays, and adversely affect Terra Energy’s production. Public perception of environmental risks associated with hydraulic fracturing can further increase pressure to adopt new laws, regulation or permitting requirements or lead to regulatory delays, legal proceedings and/or reputational impacts. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delay, increased operating costs, and third-party or governmental claims. They could also increase Terra Energy’s costs of compliance and doing business as well as delay the development of hydrocarbon (natural gas and oil) resources from shale formations, which may not be commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that Terra Energy is ultimately able to produce from its reserves.

In the event federal, provincial, local, or municipal legal restrictions are adopted in areas where Terra Energy is currently conducting, or in the future plan to conduct operations, Terra Energy may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells. In addition, if hydraulic fracturing becomes more regulated, Terra Energy’s fracturing activities could become subject to additional permitting requirements and result in permitting delays as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that Terra Energy is ultimately able to produce from its reserves.

Expiration of Licenses and Leases

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

Title

Title to oil and natural gas interests is often not capable of conclusive determination without incurring substantial expense. In accordance with industry practice, Terra Energy will conduct such title reviews in connection with its principal properties as it believes are commensurate with the value of such properties. However, no absolute assurances can be given that title defects do not exist. If title defects do exist, it is possible that Terra Energy may lose all or a portion of its right title and interest in and to the properties to which the title defects relate.

Environmental Risks

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 international conventions and federal, provincial and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach 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 Terra Energy to incur costs to remedy such discharge. In recent months, the industry has been subject to greater focus of the environmental impact of drilling and completing techniques relating to the exploration for natural gas. Changes to the requirements for drilling and completion techniques could have a material impact on the ability of Terra Energy to drill and complete wells. Implementation of strategies with respect to climate change and reducing greenhouse gases by federal or provincial governments could have a material impact on the nature of oil and natural gas operations, including those of Terra Energy. See “*INDUSTRY CONDITIONS – ENVIRONMENTAL REGULATION*”. Terra Energy is in material compliance with current environmental laws. No assurance can be given that the application of environmental laws to the business and operations of Terra Energy will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Terra Energy’s financial condition, results of operations or prospects. Terra Energy has an Environmental and Safety Committee which monitors the Corporation’s environmental and health and safety affairs.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities in oil, natural gas and natural gas liquids reserves and cash flows to be derived therefrom, including many factors beyond the Corporation’s control. The reserve and associated cash flow information set forth herein represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary 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 expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. The Corporation’s actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. Further, the evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation.

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

In accordance with applicable securities laws, GLJ, the independent reserves evaluator, has used forecast price and cost estimates in calculating reserve quantities included herein. Actual future net revenue 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 revenues derived therefrom will vary from the estimates contained in the GLJ Report, and such variations could be material. The GLJ Report is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the GLJ Report will be reduced to the extent that such activities do not achieve the level of success assumed in the GLJ Report. The GLJ Report is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Corporation’s resources since that date.

Operational Dependence

Other companies operate some of the assets in which Terra Energy has an interest. As a result, Terra Energy will have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect Terra Energy’s financial performance. Terra Energy’s return on assets operated by others will therefore depend upon a number of

factors that may be outside of Terra Energy's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Reserve Replacement

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

Reliance on Key Employees

The success of Terra Energy will be largely dependent upon the performance of its management and key employees. Terra Energy does not have any key man insurance policies, and therefore there is a risk that the death or departure of any member of management or any key employee could have a material adverse effect on Terra Energy.

Corporate Matters

To date, Terra Energy has not paid any dividends on its outstanding Common Shares and does not anticipate the payment of a regular annual dividend on its Common Shares for the foreseeable future.

Certain of the directors and officers of Terra Energy are also directors and officers of other oil and gas companies involved in oil and gas exploration and development, and conflicts of interest may arise between their duties as officers and directors of Terra Energy and as officers and directors of such other companies. Such conflicts must be disclosed in accordance with, and are subject to such other procedures and remedies as apply under the ABCA.

Management of Growth

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

Permits and Licences

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

Additional Funding Requirements

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

Variations in Foreign Exchange Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Such material increases in the value of the Canadian dollar have negatively impacted Terra Energy's operating entities production revenues in the past. Further material increases in the value of the Canadian

dollar would exacerbate this negative impact. Future increases in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates could accordingly impact the future value of Terra Energy's reserves as determined by independent evaluators.

Issuance of Debt

From time to time Terra Energy may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase Terra Energy's debt levels above industry standards. Neither Terra Energy's articles nor its bylaws limit the amount of indebtedness that Terra Energy may incur. The level of Terra Energy's indebtedness from time to time could impair Terra Energy's ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise. Terra Energy's ability to meet its debt service obligations will depend on Terra Energy's future operations which are subject to prevailing industry conditions and other factors, many of which are beyond the control of Terra Energy. As certain of the indebtedness of Terra Energy bears interest at rates which fluctuate with prevailing interest rates, increases in such rates would increase Terra Energy's interest payment obligations and could have a material adverse effect on Terra Energy's financial condition and results of operations. Further, Terra Energy's indebtedness is secured by substantially all of Terra Energy's assets. In the event of a violation by Terra Energy of any of its loan covenants or any other default by Terra Energy on its obligations relating to its indebtedness, the lender could declare such indebtedness to be immediately due and payable and, in certain cases, foreclose on Terra Energy's assets. In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

Financial Instruments

From time to time the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases. 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 its fluctuating exchange rate.

Availability of Drilling Equipment and Access Restrictions

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such equipment or access restrictions may affect the availability of such equipment to Terra Energy and may delay exploration and development activities.

Aboriginal Claims

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

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. There can be no assurance that these seasonal factors will not adversely affect the timing and scope of the Corporation's exploration and development activities, which could in turn have a material adverse impact on the Corporation's business, operations and prospects.

Third Party Credit Risk

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

cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Alternatives to and Changing Demand for Petroleum Products

Fuel 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 crude oil 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.

Emission Regulation

In 2012, Canada formally withdrew from the Kyoto Protocol, established under the United Nations Framework Convention on Climate Change which set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". Under the Copenhagen Accord, the intended successor to the Kyoto Protocol, which represents a broad political consensus rather than a binding international treaty like the Kyoto Protocol, Canada has committed to reducing its greenhouse gases emission by 17% from 2005 levels by 2020. The Government of Canada is in the process of developing future regulatory requirements that are expected to set greenhouse gas emission reduction requirements for various industrial activities, including oil and gas exploration and production. Terra Energy's exploration and production facilities and other operations and activities emit a small amount of greenhouse gases which will likely subject Terra Energy to federal law regulating emissions of greenhouse gases if and when such requirements come into force. Future federal legislation, together with provincial emission reduction requirements, such as those contained in Alberta's *Climate Change and Emissions Management Act*, British Columbia's *Greenhouse Gas Reduction (Cap and Trade) Act*, and proposed in Saskatchewan's *Management and Reduction of Greenhouse Gases Act*, may require the reduction of emissions or emissions intensity with Terra Energy's operations and facilities. The direct or indirect costs of these regulations may adversely affect the business of Terra Energy.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions and regulation on the storage and transportation of various substances produced or utilized in association with certain oil and gas industry operations and can affect the location and operation of wells and facilities and the extent to which exploration and development is permitted. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. As well, applicable environmental laws may impose remediation obligations with respect to property designated as a contaminated site upon certain responsible persons, which include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any past or present owner, tenant or other person in possession of the site. Compliance with such legislation can require significant expenditures and a breach of such legislation may result in the suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, the imposition of fines and penalties or the issuance of clean-up orders.

INDUSTRY CONDITIONS

Canadian Government Regulation

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. Outlined below are some of the more significant aspects of the relevant legislation and regulations. It is not expected that any of such controls and regulations will affect the operations of the Corporation in a manner materially different than they will affect other oil and gas companies of similar size.

Pricing and Marketing – Oil

Producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Such price depends on oil quality, price of competing oils, distance to market and the value of refined products. 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 license from the NEB and the issuance of such license requires the approval of the Governor in Council.

Pricing and Marketing – Natural Gas

The price of natural gas sold in intra-provincial and inter-provincial trade is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the government of Canada. The price received by the Corporation depends, in part, on the prices of competing natural gas and other substitute fuels, access to downstream transportation, distance to markets, length of the contract term, weather conditions, the supply and demand balance and other contractual terms. Exporters are free to negotiate prices with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than 2 years or for a term of 2 to 20 years (in quantities of not more than 30,000 m³/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 license from the NEB and the issuance of such license requires the approval of the Governor in Council.

The government of Alberta also regulates the volume of natural gas which may be removed from the province for consumption elsewhere.

The lack of firm pipeline capacity continues to limit the ability to produce and market natural gas production although pipeline expansions are ongoing. In addition, the pro-rationing of capacity on the interprovincial pipeline systems continues to limit oil exports.

The North American Free Trade Agreement

On January 1, 1994, the North American Free Trade Agreement (“NAFTA”) among the governments of Canada, the United States and Mexico became effective. NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the U.S. or Mexico will be allowed provided that the restrictions are otherwise justified under certain provisions of the General Agreement on Tariffs and Trade and then only if any export restrictions do not: (i) reduce the proportion of the energy resource exported relative to the total supply of energy resource (based upon the proportion prevailing in the most recent 36 months); (ii) impose an export price higher than the domestic price; or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory boarder restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to avoid discriminatory actions and to minimize disruption of contractual arrangements.

Provincial Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on well productivity, geographical location, field discovery data and the type or quality of the petroleum product produced.

From time to time the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Oil and gas royalty rates vary from province to province.

Alberta

Producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, 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 sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and respective market prices for the four categories of conventional oil which include light oil, medium oil, heavy oil and ultra-heavy oil. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 40 percent. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than \$85 per barrel compared to the previous royalty curve. Royalty rates for natural gas under the royalty regime

are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 36 percent. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than \$5.25/GJ compared to the previous royalty curve. Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold production taxes. The level of the freehold production tax is based on the volume of monthly production and a specified rate of tax for both oil and gas.

The Government of Alberta currently has in place two royalty programs, both of which commenced in 2008 and are intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to \$1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to \$3,750 per metre. On May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, removing a supplemental benefit of \$875,000 for wells exceeding 4,000 metres that are spud subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The five-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this new program, companies drilling new natural gas or conventional deep oil wells (between 1,000 and 3,500 metres) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the royalty regime. These options expired on February 15, 2011 and on January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to the royalty regime. The revised royalty curves for conventional oil and natural gas will not be applied to production from wells operating under the transitional royalty rates. On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. One aspect of the program was a drilling royalty credit program which provided up to a \$200 per metre royalty credit for new wells. The drilling credit program applied to wells that were drilled between April 1, 2009 and March 31, 2010 and has not been extended for wells drilled after March 31, 2010. Another aspect of the program was a new well royalty program which provided for a maximum 5 percent royalty rate for eligible new wells for the first 12 productive months or until the regulated "volume cap" was reached. The New Well Royalty Regulation, providing for the permanent implementation of this incentive program, was approved by an Order-in-Council on March 17, 2011. In addition to the foregoing, 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 percent 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 percent 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 percent 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 percent with volume and production month limits set according to the depth (including the horizontal distance) of the well, 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 at that time if it decides to discontinue the program.

British Columbia

The general oil and gas royalty structure in British Columbia is based on a sliding scale. As the price the producer receives for the gas goes up, so do the royalties that producer pays to the Province. However, the majority of gas produced in the province is also subject to a hard cap on the percentage of royalties paid. Parts 10 and 11 of the *Petroleum and Natural Gas Act* (the "PNG Act"), contain the primary legislative provisions for royalties and freehold production taxes on oil and gas in British Columbia. The Crown receives a royalty on any oil and gas production from Crown Land "permitted, licensed or leased" under the PNG Act. Authority is given to prescribe by Regulation the royalty rate, who must pay it, when it must be paid, as well as penalties for late or non-payment, and any other related considerations. The calculation of royalties payable for different classes of petroleum and natural gas and most of the practices and procedures to be followed are set out in the Petroleum and Natural Gas Royalty and

Freehold Production Tax Regulation. Natural gas is divided into ten categories, each with different royalty rates, which vary depending on the type of gas it is, whether it is freehold or Crown reserve and whether it is conservation or non-conservation gas. The results of failing to pay the royalties due can be significant, ranging from the imposition of penalties and interest to the Minister outright cancelling a permit, licence or lease pursuant to Section 135 of the PNG Act. The government has developed a number of royalty credit programs for certain types of drilling and wells. These include the following:

- Deep Royalty Credit Program (Deep, Deep Discovery, Deep Re-entry) – royalty credits are assigned based on depth, location and gas quality and is designed to target very expensive and geologically complex deep resources and which program was enhanced in February 2009 and August 2009, including to encourage greater drilling activities and allow horizontal wells starting at 1,900 metres total vertical depth to qualify for such program. Effective April 1, 2014, the Deep Royalty Credit Program will have two tiers, Tier 1 and Tier 2. Tier 1 targets shallower wells with long horizontal segments, being a well shallower than 1,900 metres and a “Deep Well Depth” (calculated based on total vertical depth plus horizontal length times horizontal length factor) greater than 2,500 metres. Wells that qualify under Tier 1 attract a 6% minimum royalty. Tier 2 targets deeper wells than Tier 1 and offers a higher maximum royalty credit. Wells that qualify under Tier 2 attract a 3% minimum royalty;
- Marginal Royalty Program – provides a reduced royalty rate based on well productivity for wells with a 12 month average rate of less than 80 mcf/d/100m and monthly production below 880 mcf/d;
- Ultra-Marginal Royalty Program – provides a reduced royalty rate based on well productivity for wells with a 12 month average rate of 40 mcf/d/100m. Effective 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 Royalty Credit Program;
- Coalbed Methane Royalty Program – provides a royalty reduction for coalbed gas wells and a royalty credit of \$50,000 for wells drilled on Crown lands and a tax credit of \$30,000 for wells drilled on freehold lands;
- Infrastructure Royalty Program – provides up to 50% of the costs of building high grade oil and gas roads and pipelines in royalty credits in order to promote activity in areas with limited infrastructure (roads/pipelines) on specific construction or drilling projects that must be approved in advance; and
- Net Profit Royalty Program – provides a 3 Tier system with low royalty rates in initial stages in exchange for higher rates in later stages in order to promote the development of remote and expensive-to-extract resources.

Under the British Columbia royalty regime, a temporary 2% gas royalty program was introduced effective September 1, 2009 whereby all natural gas wells with a spud date after August 31, 2009 and before July 1, 2010 are eligible for the 2% gas royalty, for a 12 month period, provided they commence continuous production before December 31, 2010.

In August 2012, the Government of British Columbia announced that was bringing in a nominal 2% royalty on both oil and natural gas on the revenue for the first year of production for wells drilled from September 2012 through to June 2013.

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. The amended regulation will be applied to royalties starting with the April 2013 production month. The 3% minimum royalty began showing on monthly gas royalty invoices starting in July 2013.

Saskatchewan

Effective October 1, 2002, the Government of Saskatchewan revised its fiscal regime for the oil and gas industry by introducing a number of major changes affecting the Crown royalty and freehold production tax structures and the Corporation Capital Tax Surcharge rate applicable to production from new oil and gas exploration and development activity. The changes were implemented to stimulate increased exploration and development activity in the province.

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

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

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

A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale and is produced from: (a) oil wells with a finished drilling date on or after October 1, 2002, and (b) oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas oil production ratio in any month of more than 3,500 cubic meters of gas for every cubic meter of oil. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65,000 cubic meters in a month. The associated natural gas royalty/tax regime will apply to gas produced from oil wells affected by concurrent production approvals after October 1, 2002 if the oil wells meet (a) or (b) above.

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

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

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

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

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

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

The new Upstream Petroleum Industry Associated Gas Conservation Standards (the “Gas Conservation Standards”) were announced by the Government of Saskatchewan in June 2012. The Gas Conservation Standards are designed to reduce emissions from flaring and venting of associated gas. These standards were implemented pursuant to *The Oil and Gas Conservation Act* (Saskatchewan). The Gas Conservation Standards came into effect on July 1, 2012 for new wells and facilities licensed on or after that date. For existing wells and facilities already licensed prior to July 1, 2012, the Gas Conservation Standards have an implementation date of July 1, 2015.

Land Tenure

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

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions and regulation on the storage and transportation of various substances produced or utilized in association with certain oil and gas industry operations and can affect the location and operation of wells and facilities and the extent to which exploration and development is permitted. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. As well, applicable environmental laws may impose remediation obligations with respect to property designated as a contaminated site upon certain responsible persons, which include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any past or present owner, tenant or other person in possession of the site. Compliance with such legislation can require significant expenditures and a breach of such legislation may result in the suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, the imposition of fines and penalties or the issuance of clean-up orders.

Applicable provincial environmental laws in British Columbia, Alberta and Saskatchewan are primarily found in the *Environmental Management Act*, *Environmental Protection and Enhancement Act* and the *Environmental Management and Protection Act, 2002*, respectively. The *Environmental Management and Protection Act, 2010* has received royal assent in Saskatchewan and on coming into force will repeal and replace the *Environmental Management and Protection Act, 2002*. Environmental standards and compliance for releases, clean-up and reporting in each province are strict, and there is a range of enforcement actions available, with often severe penalties. All of these provinces review energy projects through environmental assessment processes which may be held in conjunction with a federal assessment. These review processes involve public participation.

Environmental legislation in Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the “EPEA”), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the “OGCA”). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the *Climate Change and Emissions Management Amendment Act* came into effect on July 1, 2007 (“CCEMAA”). Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, namely, (i) making improvement to operations that result in reductions; (ii) purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emissions; or (iii) contributing to the Climate Change and Emissions Management Fund. Industries can either choose one of these options or a combination thereof. Pursuant to CCEMAA and the *Specified Gas Emitters Regulation*, companies were obliged to reduce their emission intensity by 12% by March 31, 2008. It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

On January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta’s projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for *in situ* oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating carbon dioxide from other emissions supporting carbon capture and storage. In addition to this action plan, the Provincial Energy Strategy unveiled on December 11, 2008 is expected to, among other things, support the upgrading, refining and petrochemical clusters existing in the Province of Alberta, market Alberta’s energy internationally, review the emission targets and carbon charges applied to large facilities, and promote the innovation of energy technology by encouraging investment in research and development.

Environmental legislation in British Columbia has largely been consolidated into the *Environmental Management Act* (British Columbia) (the “EMA”) and the *Oil and Gas Activities Act* (British Columbia) (the “OGAA”). The OGAA came into force on October 4, 2010, consolidating the numerous statutes and regulations that formerly governed the rights and responsibilities of the petroleum and natural gas industry in the province. The Environmental Protection and Management Regulation, created under the OGAA, imposes a number of obligations the petroleum and natural gas industry must meet with respect to wildlife, old-growth management areas, and water quality in streams, wetlands, lakes and aquifers. In addition, the Province has passed several pieces of legislation addressing greenhouse gas emissions, such as the *Carbon Tax Act*, *Greenhouse Gas Reduction Targets Act*, and *Greenhouse Gas Reduction (Cap and Trade) Act*, although not all provisions of the *Greenhouse Gas Reduction (Cap and Trade) Act* are currently in force. British Columbia facilities emitting more than 10,000 tonnes of greenhouse gases a year must record and report their emission levels from January 1, 2010, onwards, which is intended to form the basis for a future emissions reduction system.

In support of British Columbia's emissions reduction system, the provincial government published consultation papers for proposed regulations under the Greenhouse Gas Reduction (Cap and Trade) Act on October 22, 2010. The consultation papers contemplate an emission credits trading regime applicable to facilities in British Columbia that emit greater than 25,000 tonnes of greenhouse gases annually. Covered facilities would be required to meet compliance obligation through emission allowances, obtained by a combination of free distribution and auction, as well as emissions reduction units from offset projects or recognized compliance units from other jurisdictions.

It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation in British Columbia will continue. In addition, the Government of British Columbia has outlined strategies and initiatives in a Climate Action Plan (released June 2008) which are intended to take B.C. approximately 73% towards meeting its goal of reducing greenhouse gas emissions in the province by 33% of 2007 emission levels by 2020. British Columbia's greenhouse gas emission reduction targets were subsequently confirmed and expanded in the *Clean Energy Act*, which included a target of 80% reduction of emissions from 2007 levels by 2050. The Province's current Energy Plan (released February 2007) sets targets for zero net greenhouse gas emissions from electricity generation, the elimination of routine flaring at oil and gas producing wells and production facilities by 2016, new investments in innovation, and other measures aimed at clean energy leadership.

In May 2011, the Government of Saskatchewan passed changes to *The Oil and Gas Conservation Act* (Saskatchewan) which were subsequently proclaimed in force on April 1, 2012 with *The Oil and Gas Conservation Regulations, 2012* and *The Petroleum Registry and Electronic Documents Regulations* which set out requirements with respect to oil and gas activities, including licensing, drilling, abandonment and reclamation requirements for wells and facilities and information submission requirements with respect to the production, injection, disposition and sale of oil, gas water products and other substances.

Federal environmental laws such as the *Canadian Environmental Protection Act, 1999* and the *Fisheries Act* also apply in a variety of circumstances.

Climate change is an issue that is increasingly subject to government regulation. Although Canada ratified the Kyoto Protocol it expires in 2012 and Canada has otherwise announces its intention to withdraw from the protocol. Alberta, British Columbia and the federal Government have all introduced climate change action plans that include various means of achieving emissions or emissions intensity reductions, which may include direct reductions, emissions trading, carbon capture and storage, technology fund contributions, taxes on greenhouse gas emissions and credit for early action. Coordination between these plans has not yet been developed and remains a source of uncertainty. Given the evolving regulatory schemes related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict the final form these requirements will take or the impact on Terra Energy and its operations and financial condition at this time.

Environmental Risks

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 international conventions and federal, provincial and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach 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 Terra Energy to incur costs to remedy such discharge. In recent months, the industry has been subject to greater focus of the environmental impact of drilling and completing techniques relating to the exploration for natural gas. Changes to the requirements for drilling and completion techniques could have a material impact on the ability of Terra Energy to drill and complete wells. Implementation of strategies with respect to climate change and reducing greenhouse gases to meet the limits required by the federal or provincial governments could have a material impact on the nature of oil and natural gas operations, including those of Terra Energy. See "Industry Conditions – Environmental Regulation". Terra Energy is in material compliance with current environmental laws. No assurance can be given that the application of environmental laws to the business and operations of Terra Energy will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Terra Energy's financial condition, results of operations or prospects. Terra Energy has an Environmental and Safety Committee which monitors the Corporation's environmental and health and safety affairs.

Emission Regulation

Canada recently announced its intention to withdraw from the Kyoto Protocol, established under the United Nations Framework Convention on Climate Change which set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called “greenhouse gases” and is scheduled to expire in 2012. Under the Copenhagen Accord, the intended successor to the Kyoto Protocol, which represents a broad political consensus rather than a binding international treaty like the Kyoto Protocol, Canada has committed to reducing its greenhouse gases emissions by 17% from 2005 levels by 2020. The Government of Canada is in the process of developing future regulatory requirements that are expected to set greenhouse gas emission reduction requirements for various industrial activities, including oil and gas exploration and production. Terra Energy’s exploration and production facilities and other operations and activities emit a small amount of greenhouse gases which will likely subject Terra Energy to federal law regulating emissions of greenhouse gases if and when such requirements come into force. Future federal legislation, together with provincial emission reduction requirements, such as those contained in Alberta’s *Climate Change and Emissions Management Act*, British Columbia’s *Greenhouse Gas Reduction (Cap and Trade) Act*, and Saskatchewan’s *Management and Reduction of Greenhouse Gases Act*, may require the reduction of emissions or emissions intensity with Terra Energy’s operations and facilities. The direct or indirect costs of these regulations may adversely affect the business of Terra Energy.

DIVIDENDS OR DISTRIBUTIONS

Since its incorporation, Terra Energy has not paid any dividends or made any distributions on its Common Shares. Dividends or distributions on its Common Shares will be paid solely at the discretion of Terra Energy’s board of directors after taking into account the financial condition of Terra Energy and the economic environment in which it is operating. No regular annual dividends or distributions are expected to be paid in the foreseeable future.

DESCRIPTION OF SHARE CAPITAL

The authorized capital of Terra Energy consists of an unlimited number of Common Shares and an unlimited number of preferred shares issuable in series, of which, as at December 31, 2013, 101,663,422 Common Shares were issued and outstanding. No preferred shares are presently issued and outstanding. Terra Energy’s stock option plan was approved by shareholders on June 24, 2009 and unallocated options were approved by shareholders on June 21, 2012 and authorizes the Corporation to issue up to 10 percent of issued and outstanding Common Shares to directors, officers, employees and to consultants of the Corporation. At December 31, 2013, options to purchase 4,795,000 Common Shares were issued and outstanding.

The following is a summary of the rights, privileges, restrictions and conditions attaching to the Common Shares and the preferred shares of Terra Energy.

Common Shares

The Common Shares of Terra Energy rank junior to the preferred shares. Holders of Common Shares are entitled to one vote per share at meetings of shareholders of Terra Energy, to receive dividends if, as and when declared by the board of directors of Terra Energy and to receive pro rata the remaining property and assets of Terra Energy upon its dissolution or winding-up, subject to the rights of shares having priority over the Common Shares.

Preferred Shares

The preferred shares of Terra Energy are issuable in series and will have such rights, restrictions, conditions and limitations as the board of directors of Terra Energy may from time to time determine. The preferred shares shall rank senior to the Common Shares with respect to the payment of dividends or distribution of assets or return of capital of Terra Energy in the event of a dissolution, liquidation or winding up of Terra Energy. No preferred shares are presently issued and outstanding.

MARKET FOR SECURITIES

Price Range and Volume of Trading of Common Shares

The Common Shares of the Corporation are listed and posted for trading on the Toronto Stock Exchange and trade under the symbol "TT". The following sets forth the price range and trading volume of the Corporation's Common Shares on the Toronto Stock Exchange as reported by sources Terra Energy believes to be reliable for the periods indicated:

Period	\$ High	\$ Low	Volume Traded
2013			
January	0.250	0.220	9,034,469
February	0.250	0.220	2,085,885
March	0.250	0.220	2,071,538
April	0.245	0.210	931,859
May	0.310	0.225	821,537
June	0.335	0.275	564,224
July	0.325	0.245	1,043,952
August	0.275	0.200	275,529
September	0.240	0.200	493,615
October	0.230	0.195	535,025
November	0.240	0.150	1,110,327
December	0.315	0.200	1,897,400

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

There are no shares in escrow or subject to contractual restriction on transfer at the time of this report.

DIRECTORS AND OFFICERS

The following table sets forth the name, province and country of residence of the directors and officers, the offices held by each in the Corporation, the period served as director and the principal occupation of each during the past five years. The term of office of each director will expire at the end of the next annual meeting of shareholders of the Corporation:

Name and Province and Country of Residence	Director or Officer Since	Principal Occupation During the Last Five Years
Ralph G. Evans ⁽¹⁾⁽²⁾⁽³⁾ Alberta, Canada	Director since January 30, 2004	Mr. Evans is a professional engineer and has been the principal of R.G. Evans Consulting Inc. since 1996. Mr. Evans was employed for over 29 years with the Energy Resources Conservation Board and its predecessor regulatory body the Alberta Energy & Utilities Board in various positions including as a Board member.
Colin P. MacDonald, Q.C. ⁽⁴⁾ Alberta, Canada	Director since January 30, 2004	Mr. MacDonald is a partner in the Calgary offices of Borden Ladner Gervais LLP, a Canadian law firm. Mr. MacDonald is also a member of the Institute of Corporate Directors.
Cas H. Morel ⁽¹⁾⁽²⁾⁽⁴⁾ Alberta, Canada	Promoter President, Chief Executive Officer, Chairman and Director since January 30, 2004	Mr. Morel is the President, Chief Executive Officer and a director of Terra Energy since January 30, 2004 and has been the President and a director of Terra Capital Corp. (a private holding and management services company) since 1996. Mr. Morel was also President, Chief Executive Officer and a director of each of Rhodes Resources Corp. from October 31, 2002 to January 30, 2004 and Terrapet Energy Corp. from November 7, 1995 to January 30, 2004, prior to their amalgamation to form Terra Energy Corp.
Robert D. Penner ⁽³⁾⁽⁴⁾⁽⁵⁾ Alberta, Canada	Director since April 21, 2005 Lead Director	Mr. Penner is a Chartered Accountant and is currently an independent businessman. From 1965 until his retirement in 2004, Mr. Penner worked with KPMG LLP, Chartered Accountants and its predecessor as a senior tax partner. Mr. Penner is also a member of the Institute of Corporate Directors.

Name and Province and Country of Residence	Director or Officer Since	Principal Occupation During the Last Five Years
Tony Sabelli Alberta, Canada	Director since February 11, 2014	Mr. Sabelli is an independent businessman. August 16, 2010 to February 6, 2014, Mr. Sabelli was the Senior Vice President Operations at Sunshine Oilsands Ltd. Prior thereto, Mr. Sabelli was the Executive Vice President Alberta and Saskatchewan Operations at Terra Energy from September 7, 2009 until May 12, 2010. Mr. Sabelli also served as a director of Terra Energy from May 25, 2007 until May 12, 2010.
Brian A. Yaworski, Q.C. ⁽³⁾⁽⁴⁾ Alberta, Canada	Director since May 12, 2010	Mr. Yaworski is a Partner in the Calgary offices of the national/international law firm Davis LLP. Mr. Yaworski is also a member of the Institute of Corporate Directors.
Jan M. Campbell Alberta, Canada	Corporate Secretary since May 15, 2007	Ms. Campbell is the President of Comply Inc., a consulting firm which provides corporate secretarial services, since December 2005. From September 1997 to November 2005, Ms. Campbell was the Corporate Secretary to Precision Drilling Corporation, a predecessor to Precision Drilling Trust, a publicly traded income trust listed on the TSX and the New York Stock Exchange. Ms. Campbell is not an employee of Terra Energy, but rather serves as a consultant and as an officer on a part-time basis.
Rick A. Campbell Alberta, Canada	Vice President, Production Operations since September 27, 2013	Mr. Campbell was the General Manager of Production Operations at Terra Energy from November 1, 2012 until September 27, 2013 when he was appointed Vice President Production Operations for Terra Energy. Prior thereto, Mr. Campbell the Vice President Engineering at Argosy Energy Ltd. from September 2006 until November 2012.
Bud K. Love Alberta, Canada	Vice President, Finance and Chief Financial Officer since January 30, 2004	Mr. Love is the Vice President, Finance and Chief Financial Officer of Terra Energy since January 30, 2004. Mr. Love was the Vice President, Finance and Chief Financial Officer of Rhodes Resources Corp. from October 31, 2002 to January 30, 2004 and Vice President, Finance and Chief Financial Officer of Terrapet Energy Corp. from May 1998 to January 30, 2004, prior to their amalgamation to form Terra Energy Corp. From 1993 to February 2004, Mr. Love was the principal and founder of BKL & Associates, a full service accounting firm.
Kurt R. Musch Alberta, Canada	Controller since May 10, 2012	Mr. Musch was appointed an officer and Controller of Terra Energy May 10, 2012 and prior thereto Mr. Musch was the VP Finance and Chief Financial Officer of Perfco International Energy Inc. from October 2010 until February 2012. From March 2008 until December 2010, Mr. Musch worked as an independent consultant providing Accounting and Finance services to various oil and gas exploration companies.

Notes:

- (1) Engineering Reserves Committee member.
- (2) Environmental and Safety Committee member.
- (3) Audit Committee member.
- (4) Corporate Governance, Compensation and Nominating Committee member.
- (5) Mr. Penner was a director of Storm Cat Energy Corporation (“Storm Cat”) until September 29, 2011. In November 2008, the U.S. subsidiaries of Storm Cat filed for a voluntary petition for reorganization under Chapter 11 of the United States Bankruptcy Code and Storm Cat was subsequently delisted from the Toronto Stock Exchange and the NYSE Alternext U.S. LLC (formerly, the American Stock Exchange), which de-listings remain in effect as of the date hereof. In April 2009, pursuant to an order of the Ontario Securities Commission, the securities of Storm Cat were cease traded for a failure to file audited annual financial statements, management’s discussion and analysis and an annual information form, all for the year ended December 31, 2008 and such order remains in effect as of the date hereof.

As at March 26, 2014, the directors and officers of the Corporation, as a group, owned, directly or indirectly, or controlled or directed 26,744,551 Common Shares or approximately 25.07% of the issued and outstanding Common Shares. The information as to shares beneficially owned, directly or indirectly or over which control or direction is exercised, is based upon information furnished to the Corporation by the respective individuals indicated.

CEASE TRADE ORDERS, BANKRUPTCIES, PENALTIES OR SANCTIONS

Except as set forth herein, to the knowledge of management of the Corporation, none of the directors or executive officers of the Corporation (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 the Corporation), that 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 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.

Except as set forth herein, to the knowledge of management of the Corporation, none of the directors or executive officers of the Corporation (nor any personal holding company of any of such persons), or security holder holding a sufficient number of our securities to affect materially the control of the Corporation 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 the Corporation) 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 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.

To the knowledge of management of the Corporation, no director or executive officer of the Corporation (nor any personal holding company of any such persons), or shareholder holding a sufficient number of securities to affect materially the control of the Corporation, has been subject to 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 been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision in respect of the securities of the Corporation.

AUDIT COMMITTEE INFORMATION

Audit Committee Charter

The audit committee of Terra Energy (“Audit Committee”) is responsible for reviewing Terra Energy’s financial reporting procedures, internal controls and the performance of the external auditors. The Audit Committee Charter of Terra Energy is set forth as Appendix D of this Annual Information Form.

Composition of the Audit Committee

The current members of the Audit Committee are Robert D. Penner (Chairman), Ralph G. Evans and Brian A. Yaworski. The Audit Committee is a standing committee appointed by the board of directors of Terra Energy to assist the board of directors of Terra Energy in fulfilling its oversight responsibilities with respect to the financial reporting by Terra Energy. Each member of the Audit Committee is independent as defined under National Instrument 52-110 *Audit Committees* (“NI 52-110”) and none received any compensation, directly or indirectly, from Terra Energy other than for services as a member of the board of directors of Terra Energy and its committees, as applicable. All members of the Audit Committee are financially literate as defined in NI 52-110.

Relevant Education and Experience of Members of the Audit Committee

Robert D. Penner (Chairman)

Mr. Penner is a Chartered Accountant and is currently an independent businessman. From 1965 until his retirement in 2004, Mr. Penner worked with KPMG LLP, Chartered Accountants and its predecessor as a senior tax partner.

Ralph G. Evans

Mr. Evans is a professional engineer and has been the principal of R.G. Evans Consulting Inc. since 1996. Mr. Evans was employed for over 29 years with the Energy Resources Conservation Board and its predecessor regulatory body the Alberta Energy & Utilities Board in various positions including as a Board member.

Brian A. Yaworski, Q.C.

Mr. Yaworski is a Partner with Davis LLP, a Vancouver-based national/international law firm since February 2009.

Pre-Approval Policies and Procedures

The Audit Committee has delegated to the Chairman of the Audit Committee (or such other member of the Audit Committee who may be delegated authority), the authority to act on behalf of the Audit Committee between meetings of the Audit Committee with respect to the pre-approval of audit and permitted non-audited services provided by Deloitte LLP. The Audit Committee is required to be notified of any non-approved services over and above audit and tax. The Chairman reports on any such pre-approval at the next meeting of the Audit Committee.

Auditor Service Fees

The following table provides information about fees billed to Terra Energy and its affiliates for professional services rendered by Deloitte LLP, the Corporation's external auditor, during the fiscal year ended December 31, 2013:

Type of Service Provided (all figures in Cdn \$)	Year Ended December 31, 2013	Year Ended December 31, 2012
Audit Fees (including quarterly reviews)	216,504	256,764
Audit-Related Fees	-	-
Tax Fees	16,050	35,310
All Other Fees	4,436	3,975
Total	236,990	296,049

LEGAL PROCEEDINGS

To the knowledge of the management of Terra Energy, Terra Energy is not a party to, nor are any of Terra Energy's properties subject to any material legal proceedings. However, the Corporation is subject to non-material legal proceedings as described in Note 18 to the audited financial statements of the Corporation for the year ended December 31, 2013 (the "2013 Financial Statements"), which financial statements can be found on SEDAR at www.sedar.com and such information is incorporated herein by reference.

REGULATORY ACTIONS

There were no: (i) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority during the Corporation's last financial year; (ii) 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 during the last financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

The management of the Corporation is not aware of any material interests, direct or indirect, of any directors or executive officers of the Corporation, any person or company which beneficially owns or controls or directs, directly or indirectly, more than 10% of the outstanding Common Shares of the Corporation, or any known associate or affiliate of such persons, in any transaction within the last three financial years of the Corporation, or during the current financial year which has materially affected or is reasonably expected to materially affect the Corporation.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares of Terra Energy is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario.

MATERIAL CONTRACTS

Terra Energy has not entered into any material contracts, except for contracts previously disclosed or entered into in the ordinary course of business.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report, valuation or opinion described or included in a filing, or referred

to in a filing, made under National Instrument 51-102 by Terra Energy during, or related to, the year ended December 31, 2013 other than GLJ, Terra Energy's independent qualified reserves evaluator, and Deloitte LLP, Terra Energy's auditor. To Terra Energy's knowledge, none of the principals of GLJ had any registered or beneficial interests, direct or indirect, in any securities or other property of Terra Energy or of Terra Energy's associates or affiliates either at the time they prepared the statement, report, valuation or opinion prepared by it, at any time thereafter or to be received by them. Deloitte LLP, Terra Energy's auditor, is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

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

CONFLICTS

There are potential conflicts of interest to which the directors and officers of Terra Energy will be subject in connection with the operations of Terra Energy. In particular, certain of the directors and officers of Terra Energy are involved in managerial or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of Terra Energy or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Terra Energy. See "*DIRECTORS AND OFFICERS*". 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.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remunerations, principal holders of the Corporation's securities, options to purchase securities and interests of insiders in material transactions is contained in the Corporation's management information circular relating to its most recent annual meeting of shareholders of the Corporation. Additional financial information is contained in the Corporation's comparative financial statements and management's discussion and analysis for the year ended December 31, 2013. Additional information relating to the Corporation may be found on SEDAR at www.sedar.com.

Additional copies of this Annual Information Form, the materials listed in the preceding paragraph, any interim financial statements which have been issued by the Corporation and any other document incorporated herein by reference will be available upon request by contacting the Corporation at its offices at Suite 970, 333 – 7th Avenue S.W., Calgary, Alberta T2P 2Z1, Phone: (403) 699-7777 or Fax: (403) 264-7189.

**APPENDIX A
FORM 51-101F2
REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR OR AUDITOR**

Report on Reserves Data

This is the form referred to in item 2 of section 2.1 of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* (“NI 51-101”).

- Terms to which a meaning is ascribed in *NI 51-101* have the same meaning in this form.¹
- The report on *reserves data* referred to in item 2 of section 2.1 of *NI 51-101*, to be executed by one or more *qualified reserves evaluators or auditors independent of the reporting issuer*, must in all material respects be as follows:

To the board of directors of Terra Energy Corp. (the “Company”):

- We have evaluated the Company’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.
- The reserves data are the responsibility of the Company’s management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

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

- Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.
- The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2013 and identifies the respective portions thereof that we have evaluated and reported on to the Company’s board of directors:

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 (before income taxes, 10% discount rate \$M)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	Corporate Summary February 7, 2014	Canada	-	\$175,622	-	\$175,622

- In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
- We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

¹ For the convenience of readers, CSA Staff Notice 51-324 *Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities* sets out the meanings of terms that are printed in italics in sections 1 and 2 of this Form or in *NI 51-101, Form 51-101F1, Form 51-101F3* or Companion Policy 51-101 CP.

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

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 26, 2014

(signed) "*Myron J. Hladyshevsky*"

Myron J. Hladyshevsky, P.Eng.
Vice-President

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

This is the form referred to in item 3 of section 2.1 of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* (“NI 51-101”).

Terms to which a meaning is ascribed in *NI 51-101* have the same meaning in this form.²

The report referred to in item 3 of section 2.1 of *NI 51-101* shall in all material respects be as follows:

**Report of Management and Directors
on Reserves Data and Other Information**

Management of Terra Energy Corp. (the “Company”) are responsible for the preparation and disclosure of information with respect to the Company’s oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

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

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

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

The Engineering Reserves Committee of the board of directors has reviewed the Company’s procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors, upon recommendation of the Engineering Reserves Committee, has approved:

- a. the content and filing with securities regulatory authorities of Form 51-101F1 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.

² For the convenience of readers, Appendix 1 to Companion Policy 51-101CP sets out the meanings of certain terms in sections 1 and 2 of this Form or in NI 51-101, Form 51-101F1, Form 51-101F2 or the Companion Policy.

(signed) "*Cas H. Morel*"

Cas H. Morel
President and Chief Executive Officer

(signed) "*Bud K. Love*"

Bud K. Love
Vice President, Finance and Chief Financial Officer

(signed) "*Ralph G. Evans*"

Ralph G. Evans
Director

(signed) "*Robert D. Penner*"

Robert D. Penner
Director

March 26, 2014

APPENDIX C DEFINITIONS USED FOR RESERVE CATEGORIES

The following reserves definitions are set out by the Canadian Securities Administrators in National Instrument 51-101 (NI 51-101; in Part 2 of Appendix 1 to Companion Policy 51-101CP) with reference to the COGE Handbook.

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;
- specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

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

Proved Reserves

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.

Probable Reserves

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

Possible Reserves

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. Other criteria that must also be met for the categorization of reserves are provided in Section 5.5 of the COGE Handbook.

Development and Production Status

Each of the reserves categories (proved, probable, and possible) may be divided into developed and undeveloped categories.

Developed Reserves

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 (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

Developed Producing Reserves

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

Developed Non-Producing Reserves

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

Undeveloped Reserves

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, possible) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to 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 reserves 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 estimates are presented). Reported Reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves;
- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

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

Additional clarification of certainty levels associated with *reserves* estimates and the effect of aggregation is provided in Section 5.5.3 of the *COGE Handbook*.

Incorporation of these guidelines means that total corporate proved reserves reflect a conservative estimated and proved plus probable reserves reflect a current "best estimate" of the oil and gas quantities which will be recovered.

APPENDIX D
AUDIT COMMITTEE CHARTER

PURPOSE

The primary function of the Committee is to assist the Board of Directors (the “Board”) in fulfilling its oversight responsibilities by reviewing:

1. the financial information that will be provided to the shareholders and others;
2. the systems of internal controls, management and the Board have established; and
3. all audit processes.

Primary responsibility for the financial reporting information systems, risk management and is overseen by the Board.

COMPOSITION

1. The Committee shall be composed of a minimum of three directors, all of whom shall be independent as that term is defined in National Instrument 52-110, Audit Committees (“NI 52-110”).
2. Members shall be appointed by the Board on an annual basis, shall serve one-year terms and may serve consecutive terms, which are encouraged to ensure continuity of experience.
3. The Chair of the Committee shall be appointed by the Board for a one-year term, and may serve any number of consecutive terms.
4. All members of the Committee shall be financially literate. Financial literacy is the ability to read and understand a balance sheet, income statement and cash flow statement that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation’s financial statements.
5. The Chair shall, in consultation with management and the external auditor and internal auditor (if any), establish the agenda for the meetings and ensure that properly prepared agenda materials are circulated to the members with sufficient time for study prior to the meeting. The external auditor will also receive notice of all meetings of the Committee. The Committee may employ a list of prepared questions and considerations as a portion of its review and assessment process.
6. The Committees shall meet at least four times per year and may call special meetings as required. A quorum at meetings of the Committee shall be its Chair and one of its other members. The Committee may hold its meetings, and members of the Committee may attend meetings, by telephone conference if this is deemed appropriate.
7. The minutes of the Committee meetings shall accurately record the decisions reached and shall be distributed to Committee members with copies to the Board, the Chief Executive Officer, the Chief Financial Officer and the external auditor.
8. The Committee reviews, prior to their presentation to the Board and their release, all material financial information required by securities regulations.
9. The Committee enquires about potential claims, assessments and other contingent liabilities.
10. The Committee periodically reviews with management, depreciation and amortization policies, loss provisions and other accounting policies for appropriateness and consistency.

AUTHORITY

1. The Committee is appointed by the Board pursuant to provisions of the Business Corporations Act (Alberta) and the bylaws of the Corporation.
2. Primary responsibility for the Corporation's financial reporting; accounting systems and internal controls is vested in senior management and is overseen by the Board. The Committee is a standing committee of the Board established to assist it in fulfilling its responsibilities in this regard. The Committee shall have responsibility for overseeing management reporting on internal controls. While it is management's responsibility to design and implement an effective system of internal control, it is the responsibility of the Committee to ensure that management has done so.
3. The Committee shall have unrestricted access to the Corporation's personnel and documents and will be provided with the resources necessary to carry out its responsibilities.
4. The Committee shall have direct communication channels with the internal auditors (if any) and the external auditors to discuss and review specific issues as appropriate.
5. The Committee shall have the sole authority to retain (or terminate) advisors or consultants as it determines necessary to assist the Committee in discharging its functions hereunder. The Committee shall be provided with the necessary funding to compensate the advisors or consultants retained by the Committee.

RELATIONSHIP WITH EXTERNAL AUDITORS

1. An external auditor must report directly to the Committee.
2. The Committee is directly responsible for overseeing the work of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the issuer, including the resolution of disagreements between management and the external auditor regarding financial reporting.
3. The Committee shall implement structure and procedures to ensure that it meets with the external auditor on a regular basis in the absence of management.

ACCOUNTING SYSTEMS, INTERNAL CONTROLS AND PROCEDURES

1. The Committee shall obtain reasonable assurance from discussions with and/or reports from management, and reports from external auditors that accounting systems are reliable and that the prescribed internal controls are operating effectively for the Corporation and its subsidiaries and affiliates.
2. The Committee shall review to ensure to its satisfaction that adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements and will periodically assess the adequacy of those procedures.
3. The Committee shall review with the external auditor the quality and not just the acceptability of the Corporation's accounting principles and direct the external auditor's examinations to particular areas.
4. The Committee will review control weaknesses identified by the external auditor's, together with management's response and review with external auditors their view of the qualifications and performance of the key financial and accounting executives.
5. In order to preserve the independence of the external auditor, the Committee will:
 - a) recommend to the Board the external auditor to be nominated for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation;
 - b) recommend to the Board the compensation of the external auditor's engagement; and

- c) review and pre-approve any engagements for non-audit services to be provided by the external auditors or its affiliates, together with estimated fees, and consider the impact, if any, on the independence of the external auditor.
- 6. The Committee will review with management and with the external auditor any proposed changes in major accounting policies, the presentation and impact of significant risks and uncertainties, and key estimates and judgements of management that may be material to financial reporting.
- 7. The Committee shall establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters and the confidential anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.
 - d) The Committee shall establish a periodic review procedure to ensure that the external auditor complies with the Canadian Public Accountability Regime under Multilateral Instrument 52-108, Auditor Oversight.
- 8. The Committee shall review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former external auditor of the Corporation.

STATUTORY AND REGULATORY RESPONSIBILITIES

- 1. Annual Financial Information – review the annual audited financial statements, including Letter to Shareholders and related press releases and recommend their approval to the Board, after discussing matters such as the selection of accounting policies (and changes thereto), major accounting judgments, accruals and estimates with management and the external auditor.
- 2. Annual Report – review the management discussion and analysis (“MD & A”) section and all other relevant sections of the annual report to ensure consistency of all financial information included in the annual report.
- 3. Interim Financial Statements – review the quarterly interim financial statements, including the Letter to Shareholders and related press releases and recommend their approval to the Board.
- 4. Earnings Guidance/Forecasts – review forecasted financial information and forward looking statements.
- 5. In addition, the Committee must review the Corporation's financial statements, MD & A and earnings press releases before the Corporation publicly discloses this information.

REPORTING

- 1. The Committee will report, through the Chairperson of the Committee, to the Board following each meeting on the major discussions and decisions made by the Committee, and report annually to the Board on the Committee's responsibilities and how it has discharged them.
- 2. In addition, the Committee will review and reassess these Terms of Reference annually and recommended any proposed changes to the Corporate Governance and Compensation Committee.

OTHER RESPONSIBILITIES

- 1. Investigating fraud, illegal acts or conflicts of interest.
- 2. Discussing selected issues with corporate counsel or the outside auditor or management.