TOURMALINE OIL CORP.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2010

March 25, 2011

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SCHEDULES

CONVENTIONS

Unless otherwise indicated, any reference in this Annual Information Form to "**Tourmaline**" or the "**Company**" means Tourmaline Oil Corp. Certain other terms used but not defined herein are defined in National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") and in the Canadian Oil and Gas Evaluation Handbook Volume I (the "**COGE Handbook**"). Unless otherwise specified, information in this Annual Information Form is as at the end of the Company's most recently completed financial year, being December 31, 2010. All dollar amounts herein are in Canadian dollars, unless otherwise stated. See "Selected Abbreviations", "Selected Conversions", "Forward-Looking Statements" and "Certain Reserves Data Disclosure".

CORPORATE STRUCTURE

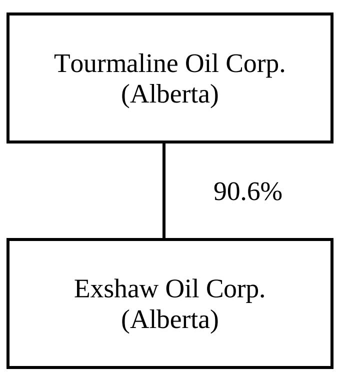
Name, address and incorporation

Tourmaline Oil Corp. was incorporated under the *Business Corporations Act* (Alberta) (the "**ABCA**") under the name "1415065 Alberta Ltd." on July 21, 2008. On August 26, 2008, Tourmaline filed Articles of Amendment to change its name to "Tourmaline Oil Corp.". On October 24, 2008, Tourmaline filed Articles of Amendment to: (i) create a new class of shares designated as first preferred shares (the "**First Preferred Shares**"), issuable in series, and a new class of shares designated as second preferred shares (the "**Second Preferred Shares**"), issuable in series, and amend the terms of the common shares (the "**Common Shares**"); (ii) remove the "private company" restrictions; and (iii) change the minimum number of directors of the Company from one to three. Tourmaline amalgamated with its wholly-owned subsidiaries Pienza Petroleum Inc. ("**Pienza**") and Vigilant Exploration Inc. ("**Vigilant**") on January 1, 2010, and amalgamated with its wholly-owned subsidiary Altia Energy Ltd. ("**Altia**") on January 1, 2011, in each case continuing as Tourmaline Oil Corp.

Tourmaline's head office is located at Suite 3700, 250 – 6th Avenue S.W., Calgary, Alberta T2P 3H7 and its registered office is located at Suite 1400, 350 – 7th Avenue S.W., Calgary, Alberta T2P 3N9.

Intercorporate relationships

The following diagram illustrates the intercorporate relationship between Tourmaline and its material subsidiary, the percentage of votes attached to all voting securities of the subsidiary beneficially owned, or controlled or directed, directly or indirectly, by Tourmaline and the jurisdiction of incorporation of the subsidiary.



DESCRIPTION OF THE BUSINESS

Overview

Tourmaline is a Canadian intermediate crude oil and natural gas exploration and production company focused on long-term growth through an aggressive exploration, development, production and acquisition program in the Western Canadian Sedimentary Basin ("**WCSB**"). Tourmaline commenced active operations in the fall of 2008 with the objective of building a successful Canadian intermediate crude oil and natural gas exploration, development and production company with a long-term business strategy similar to that of Duvernay Oil Corp.

("**Duvernay**") and Berkley Petroleum Corp. ("**Berkley**"), companies previously founded and managed by certain key members of Tourmaline's senior management team. Through a series of strategic acquisitions, farm-ins and land acquisitions combined with its active capital exploration and development program, Tourmaline has grown current production to approximately 24,000 Boe/d and an estimated 10,000 Boe/d behind pipe awaiting tie-in at March 24, 2011. The Company has assembled extensive undeveloped land position with a large, multi-year drilling inventory and operating control of important natural gas processing and transportation infrastructure in two core long-term growth areas – the Alberta Deep Basin and the Greater Peace River High.

To date, the Company has raised close to $1.23 billion through private placement equity financings and its initial public offering, approximately $310 million of which was raised from Tourmaline's directors, officers, employees and their associates, and strategically completed 17 acquisitions to cost-effectively build its current production and extensive land position. The acquisitions have been complemented by an aggressive exploration, development and production program that is intended to be the Company's primary long-term growth engine.

Management believes that the location, size, concentration and other attributes of the Company's two core long-term growth areas provide an opportunity for the Company to achieve operating cost, reserve recovery, deliverability and production efficiencies through a large-scale, repeatable capital exploration and development program. Tourmaline is aggressively executing this program using principally 3D seismic data to identify drilling locations for multi-stage fracture stimulations of vertical and horizontal wells. A key component of Tourmaline's long-term business strategy has always been to be one of the lowest cost operators within its core areas. In Tourmaline's view, striving to be a low cost operator is especially important in the current natural gas price environment.

Business Strategy

Tourmaline's long-term business strategy is to increase shareholder value by building an extensive asset base over two to three core exploration and production areas and exploiting and developing these areas to increase reserves, production and cash flows at an attractive return on invested capital. The Company seeks to execute this strategy by: aggressively drilling and developing its extensive undeveloped land position; adopting and employing advanced drilling and completion techniques; enhancing returns by focusing on operational and cost efficiencies; pursuing strategic acquisitions with significant potential synergies; and undertaking wildcat exploration drilling for new pool discoveries.

General Development of the Business

2008

Tourmaline completed its initial equity financings totalling approximately $326 million in October and December 2008, in the midst of the "world financial crisis", to provide it with the necessary capital to commence active operations and the execution of its long-term business strategy.

Two minor transactions were completed in the fall of 2008 which established Tourmaline's presence in the Alberta Deep Basin, a play area where Tourmaline's management and technical staff have extensive exploration and operating experience and have had historical success. The first was the execution of a farm-in on approximately 100 sections of land in the Ansel-Minehead area of the Alberta Deep Basin with a senior Canadian producer. The second was the acquisition of producing natural gas assets and associated undeveloped lands from another senior Canadian producer in the Smoky-Horse area of the Alberta Deep Basin.

2009

During the first half of 2009, Tourmaline took advantage of a relatively weak natural gas price environment and its strong balance sheet to complete a series of asset acquisitions in the Alberta Deep Basin. Management believes that the acquired assets have considerable additional reserve and production potential and the Company developed a parallel long-term plan to enhance and control the associated natural gas infrastructure facilities. Eight such asset transactions were completed during 2009, providing Tourmaline with a strong production base and an extensive inventory of future potential drilling locations. To fund these acquisitions, the Company raised an additional approximately $348.4 million through two private placement equity financings in 2009.

Tourmaline established a second core exploration and production area in the Greater Peace River High (as defined herein) area of Alberta and north east British Columbia ("**NEBC**") during the second half of 2009 and early 2010 through the Pienza, Exshaw Oil Corp. ("**Exshaw**"), Vigilant and Altia acquisitions. Pienza, Exshaw and Vigilant were acquired in 2009 and Altia was acquired in early 2010. These transactions allowed Tourmaline to establish a strong position in the Montney play area, another play area where Tourmaline's management and technical staff have had extensive technical experience and have had historical success. Within the Greater Peace River High, Tourmaline has also assembled a large land position and drilling location inventory in the Sunrise-Dawson area of NEBC, which is considered by management to be the optimum Montney play area in the entire NEBC Montney trend. To complement these acquisitions, Tourmaline also entered into a joint venture with a Canadian intermediate producer in the Elmworth area of Alberta, another attractive developing Montney play area within the Greater Peace River High.

The third main component of the Company's Greater Peace River High core exploration and production area is the Spirit River area of Alberta. This area, acquired pursuant to the Exshaw acquisition, features crude oil and natural gas accumulations in 10 separate horizons, all of which have attractive future development inventories. The main pool, the Charlie Lake formation, has up to 40 vertical and 50 horizontal drilling locations, which are included in the Company's drilling location inventory.

2010

Tourmaline completed a private placement equity financing in March of 2010, raising approximately $224 million. This financing provided the Company with the funds required to pursue additional, sizeable asset acquisitions that were available for sale during the first half of 2010.

In June 2010, Tourmaline completed an acquisition of crude oil and natural gas assets in the Alberta Deep Basin. Pursuant to this acquisition, Tourmaline acquired from a senior Canadian producer approximately 4,000 Boe/d of production and 462 gross (356 net) sections of developed and undeveloped lands in the Alberta Deep Basin. This acquisition consolidated the Company's position as one of the largest producers and land and drilling inventory holders in the entire Alberta Deep Basin.

In August 2010, Tourmaline completed a private placement equity financing of "flow-through" Common Shares for aggregate proceeds of $25.3 million.

On November 1, 2010, Tourmaline acquired additional petroleum and natural gas properties and related assets in the Alberta Deep Basin for a cash purchase price of approximately $50.4 million.

In November and December of 2010, Tourmaline completed its initial public offering and a concurrent private placement raising approximately $259.3 million.

Recent Developments

On March 8, 2011, Tourmaline completed a private placement equity of 1,580,000 "flow-through" Common Shares at a price of $30.00 per share for aggregate proceeds of $47.4 million.

Significant Acquisition Summary

The following table summarizes the Company's significant acquisitions since inception.

Significant Acquisition Summary

Date	Acquisition	Areas	Purchase Price (MM$)[1]	Production[2] (Boe/d)	Undeveloped Land Gross Acres	Undeveloped Land Net Acres
April 30, 2009	Alberta Deep Basin acquisition	Hinton/Musreau/ Narraway	$103.0	2,350	86,072	27,466
August 28, 2009	Wild River acquisition	Wild River/ Harley/ Olsen/Sundance	$145.9	2,550	44,196	24,016
September 15, 2009	Pienza acquisition[3]	Sunrise NEBC	$50.0	350	23,348	15,980
November 10, 2009	Exshaw acquisition	Peace River Arch	$131.8	2,510	56,960	41,718
November 10, 2009	Vigilant acquisition[3]	Musreau/Chime/ Whitecourt	$47.5	650	92,734	88,538
January 14, 2010	Altia acquisition[4]	Dawson NEBC	$100.8	1,500	122,600	56,980
June 1, 2010	Greater Hinton acquisition	Greater Hinton	$275.0	4,000	266,849	204,560
			$854.0	**13,910**	**692,759**	**459,258**

Notes:

(1) These amounts reflect the purchase price paid in cash and/or Common Shares and associated transaction costs.
(2) Estimated production as at the effective date of the acquisition.
(3) Subsequent to the Pienza and Vigilant acquisitions, Tourmaline amalgamated with Pienza and Vigilant on January 1, 2010 under the ABCA, continuing as Tourmaline Oil Corp.
(4) Subsequent to the Altia acquisition, Tourmaline amalgamated with Altia on January 1, 2011 under the ABCA, continuing as Tourmaline Oil Corp.

Summary of Equity Financings

The following table summarizes the equity financings completed by the Company since commencement of active operations as well as Company insider, employee and associate participation in such equity financings.

Summary of Equity Financings

Date	Financings: Shares Issued	Financings: Total Gross Proceeds	Insider, Employee and Associate Participation[9]: Gross Subscriptions	Insider, Employee and Associate Participation[9]: Percentage of Gross Proceeds
October 27, 2008	50,500,000[1]	$301,000,000	$147,000,000	48.8%
December 17, 2008	2,500,000[2]	$25,000,000	$12,500,000	50.0%
May 28, 2009	14,000,000[3]	$140,000,000	$30,000,000	21.4%
November 10, 2009	13,543,624[4]	$208,404,360	$47,904,360	23.0%
March 19, 2010	11,950,000[5]	$223,920,000	$36,720,000	16.4%
August 12, 2010	1,150,000[6]	$25,300,000	$6,600,000	26.1%
November 23, 2010	12,350,000[7]	$259,350,000	$17,850,000	6.9%
March 8, 2011	1,580,000[8]	$47,400,000	$11,400,000	24.1%
	107,573,624	$1,230,374,360	$309,974,360	25.1%

Notes:

(1) Private placement of 15,000,000 Common Shares at $3.50 per share and 35,500,000 Common Shares at $7.00 per share.
(2) Private placement of 2,500,000 flow-through Common Shares at $10.00 per share.
(3) Private placement of 14,000,000 Common Shares at $10.00 per share.
(4) Private placement of 11,793,624 Common Shares at $15.00 per share and 1,750,000 flow-through Common Shares at $18.00 per share.
(5) Private placement of 9,500,000 Common Shares at $18.00 per share and 2,450,000 flow-through Common Shares at $21.60 per share.
(6) Private placement of 1,150,000 flow-through Common Shares at $22.00 per share.
(7) Initial public offering of 12,350,000 Common Shares at $21.00 per share which includes the issuance of 1,500,000 Common Shares issued pursuant to the exercise of the underwriters' over-allotment option (completed on December 23, 2010) and 850,000 Common Shares issued pursuant to a concurrent private placement to certain executive officers.
(8) Private placement of 1,580,000 flow-through Common Shares at $30.00 per share.
(9) Represents percentage of insider, employee and associate participation for the total amount raised by the Company, which has been calculated based on the percentage of Common Shares issued to directors, officers, employees and other service providers of the Company and certain family, friends and business associates of the foregoing relative to the total number of Common Shares issued in each financing.

DESCRIPTION OF CORE LONG-TERM GROWTH AREAS

The following is a description of Tourmaline's two core long-term growth areas – an area within the WCSB approximately 250 km west of Edmonton, Alberta (the "**Alberta Deep Basin**") and an area within the WCSB extending from Grand Prairie, Alberta to approximately 30 km southwest of Fort St. John, NEBC (the "**Greater Peace River High**").

Alberta Deep Basin Core Area

The Alberta Deep Basin core area is a multi-objective tight natural gas sand play area with up to 15 separate lower Cretaceous tight natural gas sand reservoirs. Tourmaline's target exploration and production area is in that portion of the Alberta Deep Basin where the entire lower Cretaceous stratigraphic section is gas saturated. The primary vehicle for accessing these extensive reserves in stacked sandstones is multi-stage fracture stimulation in vertical well-bores. Tourmaline uses 3D seismic data to select the majority of its drilling locations, and management believes it is an industry leader in adopting and adapting the improving drilling and completion technologies. The majority of the Company's working interest lands have already received approval for down-spacing at four vertical wells per section.

Certain formations within the lower Cretaceous stack of tight sand reservoirs in the Alberta Deep Basin are more amenable to horizontal drilling (including the Cardium, Wilrich, Second Specks and Nikinassin Formations). Accordingly, each section in the Alberta Deep Basin core area may include one or two targeted multi-phase stimulated horizontal wells in the Company's long-term development plan. Management estimates that up to 1,500 gross horizontal drilling locations exist in the Alberta Deep Basin which are currently being assessed as part of the ongoing drilling program. These horizontal drilling locations have been included in the Company's drilling locations inventory. Future evaluation of these "embedded" resource plays is an important component of the 2011 capital exploration and development program, with several horizontal wells planned. When developed, these embedded resource plays will utilize the natural gas infrastructure being constructed for vertical well development and downspacing.

The assets acquired pursuant to the Greater Hinton Acquisition in June of 2010 consisted of production of approximately 4,000 Boe/d, proved plus probable reserves of approximately 30 MMboe and significant working interests in over 462 sections of land. Management believes the Greater Hinton Acquisition further solidified the Company as one of the leading natural gas producers in the Alberta Deep Basin.

Tourmaline has ownership interests in four natural gas plants in the Alberta Deep Basin, two of which, the Wild River 14-20 plant (70% owned) and the Hinton 6-32 gas plant (100% owned), are operated by Tourmaline. In addition, Tourmaline owns and operates a substantial compression and dehydration facility at Horse capable of processing approximately 50 MMcf/d of natural gas. Tourmaline's goal is to be the lowest-cost, most efficient operator in the Alberta Deep Basin, and during the next 12 to 18 months, the Company plans to optimize and systematically reduce costs of operating the assets acquired in 2009 and 2010 as well as the new properties being developed.

Tourmaline has assembled a land portfolio in the Alberta Deep Basin that is more than three times larger than that held by Duvernay at the time of its sale (approximately 1,650 gross sections at an average 76% working interest compared to approximately 450 gross sections). This land portfolio equates to approximately 3,100 drilling locations based on only two wells per section. The Company also has a recompletion inventory of over 100 wells in the Alberta Deep Basin.

In the Alberta Deep Basin, Tourmaline drilled 29 natural gas wells in 2009, and drilled 49 gross natural gas wells as well as 10 recompletions in 2010. Tourmaline's net production in the Alberta Deep Basin grew through 15,000 Boe/d in June 2010 and is currently estimated at approximately 19,000 Boe/d with further production growth anticipated through the balance of the year. The Company estimates that it currently has approximately 6,600 Boe/d behind pipe awaiting tie-in. Year-end 2010 proved plus probable reserves were 105.6 MMboe in the Alberta Deep Basin, with approximately 150 of the 3,100 drilling locations recognized in the Consolidated Reserve Report.

Greater Peace River High Core Area

Tourmaline has assembled its second core exploration and production area in the Greater Peace River High where the primary focus is liquids rich natural gas in the Triassic Montney formation. Industry participants have been pursuing Triassic Montney plays and reservoirs in the WCSB for over four decades. Exploration and production of the Montney has evolved over time from conventional reservoirs in the south east portion of the play area in Alberta to unconventional Montney reservoirs in the Peace River Arch area of Alberta and NEBC. Technological developments, including the drilling of horizontal multi-stage fracture stimulation wells, have allowed access to the thickest, highest pressured and highest deliverability Montney in the NEBC play area. It is in this Groundbirch/Sunrise/Dawson area of the Peace River Arch where senior management of Tourmaline gained extensive experience with Duvernay and where Tourmaline has concentrated its exploration and production program.

The Company has assembled its large Montney position primarily through the acquisitions completed in 2009 and early 2010. In NEBC, Tourmaline has an inventory of over 300 horizontal Montney development drilling locations in the Sunrise/Dawson area, making the Company one of the largest participants in this resource play. In the Greater Peace River High, Tourmaline has drilled 21 Montney multi-stage fracture stimulated horizontal natural gas wells, two Charlie Lake horizontal oil wells and one vertical oil well to date with an additional 18 to 20 Montney horizontal wells planned for the balance of 2011.

Complementing this growing Montney drilling inventory in NEBC is a series of high deliverability/low operating cost sweet Mississippian Kiskatinaw and Wabamun natural gas pools. Management believes that these deeper pools also have considerable exploration and production potential and will be the subject of ongoing exploration and development in 2011 and 2012. In addition, Tourmaline has completed the construction of an operated natural gas processing facility and gathering system.

In the Alberta portion of the Greater Peace River High area, Tourmaline has secured access to 80 gross (38.75 net) sections of prospective acreage in the rapidly developing Montney play at Elmworth through a joint venture with a Canadian intermediate oil and gas company. There are in excess of 100 drilling locations on this land block which are included in the Company's drilling inventory. Three Tourmaline-operated horizontal delineation wells have been drilled to date in advance of a more substantial development drilling plan. Complementing this Montney project in Alberta is the Company's producing complex at Spirit River, Alberta. The majority of the production at Spirit River is derived from oil and natural gas-charged reservoirs of the Triassic Charlie Lake formation. This area, currently producing approximately 2,500 Boe/d, has a large inventory of vertical and horizontal development drilling prospects in the Charlie Lake formation as well as attractive plays in several other formations. Initial horizontal drilling results have been positive.

Tourmaline's total net production in the Greater Peace River High area is currently estimated at approximately 5,000 Boe/d and year-end 2010 proved plus probable reserves were 52.5 MMboe.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Date of Statement

The statement of reserves data and other oil and gas information set forth below is dated March 25, 2011 and effective as at December 31, 2010.

Disclosure of Reserves Data

The reserves data set forth below is based upon the report of GLJ Petroleum Consultants Ltd. ("**GLJ**") dated effective December 31, 2010, with a preparation date of February 25, 2011 (the "**GLJ Reserve Report**") and the report of AJM Petroleum Consultants ("**AJM**") dated effective December 31, 2010, with a preparation date of February 25, 2011 (the "**AJM Reserve Report**"), which are contained in the consolidated report of GLJ dated effective December 31, 2010, with a preparation date of February 25, 2011 (the "**Consolidated Reserve Report**").

The Consolidated Reserve Report evaluated, as at December 31, 2010, the crude oil, NGL and natural gas reserves of Tourmaline and its consolidated subsidiary Exshaw.

GLJ evaluated in the GLJ Reserve Report approximately 59% of the assigned total proved plus probable reserves and 58% of the total proved plus probable future net revenue discounted at 10%. AJM evaluated in the AJM Reserve Report approximately 41% of the assigned total proved plus probable reserves and 42% of the total proved plus probable future net revenue discounted at 10%. AJM evaluated in the AJM Reserve Report the Company's Greater Hinton property located in the Alberta Deep Basin and Exshaw's properties, which are located in the Alberta portion of the Peace River High. AJM incorporated the GLJ forecast price and cost assumptions in their evaluation. GLJ evaluated in the GLJ Reserve Report the balance of the Company's properties.

GLJ prepared the Consolidated Reserve Report by consolidating the GLJ Reserve Report with the AJM Reserve Report adjusted to apply certain of GLJ's assumptions and methodologies used in the preparation of the GLJ Reserve Report to the AJM Reserve Report including GLJ's pricing and cost assumptions. Accordingly, the consolidated reserves information below varies from the reserve information that would be derived from a simple arithmetic summation of the GLJ Reserve Report and the AJM Reserve Report. Also due to rounding, certain columns may not add.

In accordance with NI 51-101, the Consolidated Reserve Report and the AJM Reserve Report include 100% of the reserves and future net revenue attributable to Exshaw's properties, without reduction to reflect the 9.4% third-party minority interest in Exshaw. Accordingly, the reserves data for the Company's consolidated reserves set forth below, which has been derived from the Consolidated Reserve Report, reflects 100% of Exshaw's reserves and future net revenue without reduction to reflect the third-party minority interest. Approximately 1.0% of the assigned total proved plus probable reserves and 1.7% of the total proved plus probable future net revenue discounted at 10% in the Consolidated Reserve Report is attributable to the 9.4% third-party minority interest in Exshaw.

The Consolidated Reserve Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and the COGE Handbook. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which Tourmaline believes is important to readers of this Annual Information Form. GLJ and AJM were engaged to provide evaluations of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Company's consolidated reserves are in Canada and, more specifically in the provinces of Alberta and British Columbia.

The applicable Reports on Reserves Data by Independent Qualified Reserves Evaluators in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached as Schedules A through C to this Annual Information Form.

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

The information relating to the Company's crude oil, NGL and natural gas reserves contains forward-looking statements relating to future net revenues, forecast capital expenditures, future development plans and costs related thereto, forecast operating costs, anticipated production and abandonment costs. See "Forward-Looking Statements", "Certain Reserves Data Information", "Industry Conditions" and "Risk Factors – Reserves Estimates".

Reserves and Future Net Revenue Data (Forecast Prices and Costs)

Summary of Crude Oil and Natural Gas Reserves and
Net Present Values of Future Net Revenue
as of December 31, 2010
Forecast Prices and Costs

	Light and Medium Crude Oil		Natural Gas		NGL	
Reserves Category	**Company Gross (Mbbls)**	**Company Net (Mbbls)**	**Company Gross (MMcf)**	**Company Net (MMcf)**	**Company Gross (Mbbls)**	**Company Net (Mbbls)**
Proved Developed Producing..........................	997	829	211,683	189,799	2,635	1,859
Proved Developed Non-Producing	163	148	41,052	37,613	526	419
Proved Undeveloped	2,711	2,027	234,358	210,995	4,801	3,929
Total Proved Reserves.....................................	3,870	3,004	487,093	438,407	7,962	6,207
Total Probable Reserves..................................	2,608	1,996	342,272	307,951	5,512	4,263
Total Proved Plus Probable Reserves	6,479	5,000	829,365	746,357	13,474	10,470

Net Present Values Of Future Net Revenue ($000s)

	Before Future Income Taxes Discounted at (%/year)					After Future Income Taxes Discounted at (%/year)					Unit Value Before Income Tax Discounted at 10%/year	
Reserves Category	**0**	**5**	**10**	**15**	**20**	**0**	**5**	**10**	**15**	**20**	**($/Mcfe)**	**($/Boe)**
Proved Developed Producing	991,358	741,506	594,602	498,869	431,776	991,358	741,506	594,602	498,869	431,776	2.89	17.32
Proved Developed Non-Producing	153,521	115,496	91,923	76,046	64,681	153,521	115,496	91,923	76,046	64,681	2.24	13.45
Proved Undeveloped..........................	929,038	564,329	359,676	233,205	149,223	780,176	484,601	313,798	205,301	131,495	1.46	8.75
Total Proved Reserves	2,073,916	1,421,331	1,046,201	808,119	645,679	1,925,054	1,341,603	1,000,323	780,216	627,952	2.12	12.72
Total Probable Reserves	1,824,046	911,450	526,287	330,748	218,071	1,368,383	679,952	388,518	240,369	154,912	1.52	9.14
Total Proved Plus Probable Reserves	3,897,963	2,332,781	1,572,488	1,138,867	863,750	3,293,438	2,021,555	1,388,841	1,020,585	782,864	1.87	11.24

Total Future Net Revenue ($000s)
(Undiscounted)
as of December 31, 2010
Forecast Prices and Costs

Reserves Category	**Revenue**	**Royalties**	**Operating Costs**	**Development Costs**	**Abandonment and Reclamation Costs**	**Future Net Revenue Before Deducting Future Income Tax Expenses**	**Future Income Tax Expenses**	**Future Net Revenue After Future Income Tax Expenses**
Proved	4,290,590	534,922	1,031,982	609,803	39,966	2,073,916	148,862	1,925,054
Proved Plus Probable	7,949,475	981,139	1,989,924	1,018,455	61,994	3,897,963	604,525	3,293,438

Future Net Revenue
by Production Group
as of December 31, 2010
Forecast Prices and Costs

			Unit Value (discounted at 10%/year)	
Reserves Category	**Production Group**	**Future Net Revenue Before Income Taxes (discounted at 10%/year) ($000s)**	**($/Mcfe)**	**($/Boe)**
Proved Reserves	Light and Medium Crude Oil	2,539	5.46	32.75
	Natural Gas (including by-products but excluding solution gas)	1,043,662	2.12	12.70
	Total	1,046,201	2.12	12.72

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($000s)	Unit Value (discounted at 10%/year) ($/Mcfe)	Unit Value (discounted at 10%/year) ($/Boe)
Proved Plus Probable	Light and Medium Crude Oil	2,813	5.06	30.37
	Natural Gas (including by-products but excluding solution gas)	1,569,676	1.87	11.23
	Total	1,572,488	1.87	11.24

Reconciliation of Changes in Reserves

Reconciliation of Gross Reserves
by Principal Product Type
Forecast Prices and Costs

	Light and Medium Crude Oil			Natural Gas		
Factors	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**
December 31, 2009	**1,868**	**2,871**	**4,739**	**185,249**	**121,702**	**306,951**
Discoveries	0	0	0	0	0	0
Extensions	2,017	(331)	1,686	125,555	73,383	198,938
Infill Drilling	0	0	0	5,141	4,367	9,508
Improved Recovery	0	0	0	902	1,878	2,780
Technical Revisions	587	224	811	(579)	5,280	4,701
Acquisitions	52	16	68	216,387	139,276	355,663
Dispositions	(275)	(142)	(417)	(6,320)	(3,330)	(9,650)
Economic Factors	(93)	(29)	(122)	(847)	(284)	(1,131)
Production	(286)	0	(286)	(38,395)	0	(38,395)
December 31, 2010	**3,870**	**2,609**	**6,479**	**487,093**	**342,272**	**829,365**

	NGL			BOE		
Factors	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**
December 31, 2009	**2,106**	**1,355**	**3,461**	**34,849**	**24,510**	**59,359**
Discoveries	0	0	0	0	0	0
Extensions	4,858	3,078	7,936	27,800	14,978	42,778
Infill Drilling	66	58	124	923	786	1,709
Improved Recovery	7	8	15	157	321	478
Technical Revisions	855	760	1,615	1,345	1,864	3,209
Acquisitions	613	309	922	36,730	23,537	60,267
Dispositions	(101)	(54)	(155)	(1,429)	(751)	(2,180)
Economic Factors	(9)	(2)	(11)	(243)	(79)	(322)
Production	(432)	0	(432)	(7,117)	0	(7,117)
December 31, 2010	**7,962**	**5,512**	**13,474**	**93,015**	**65,166**	**158,181**

Notes to Reserves Data Tables:

(1) Columns may not add due to rounding.
(2) Tourmaline has no unconventional reserves (bitumen, synthetic crude oil, natural gas from coal or heavy oil).
(3) The crude oil, NGL and natural gas reserve estimates in this Annual Information Form are based on the definitions and guidelines contained in the COGE Handbook.

GLJ Reserve Report Pricing Assumptions

Summary of Pricing and Inflation Rate Assumptions
Forecast Prices and Costs (1)

Crude Oil and Natural Gas Liquids Pricing

Year	Inflation (2)	Bank of Canada Average Noon Exchange Rate $US/$Cdn (3)	NYMEX WTI Near Month Futures Contract Crude Oil at Cushing Oklahoma		ICE BRENT Near Month Futures Contract Crude Oil FOB North Sea Then Current $Cdn/Bbl	Light, Sweet Crude Oil (40 API, 0.3%S) at Edmonton Then Current $Cdn/Bbl	Bow River Crude Oil Stream Quality at Hardisty Then Current $Cdn/Bbl	WCS Stream Quality at Hardisty Then Current $Cdn/Bbl	Heavy Crude Oil Proxy (12 API) at Hardisty Then Current $Cdn/Bbl	Light Crude Oil (35 API, 1.2%S) at Cromer Then Current $Cdn/Bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer Then Current $Cdn/Bbl	Alberta Natural Gas Liquids (Then Current Dollars)			
			Constant 2011 $ $US/Bbl	Then Current $US/ Bbl								Spec Ethane $Cdn/Bbl	Edmonton Propane $Cdn/Bbl	Edmonton Butane $Cdn/Bbl	Edmonton Pentanes Plus $Cdn/Bbl
2011 Q1.........	2.0	0.980	88.00	88.00	89.00	85.71	76.29	75.40	69.50	83.57	82.29	13.22	54.00	66.86	90.00
2011 Q2.........	2.0	0.980	88.00	88.00	88.50	85.71	76.29	75.40	69.50	83.57	82.29	13.22	54.00	66.86	90.00
2011 Q3.........	2.0	0.980	88.00	88.00	88.50	86.73	76.33	75.43	69.21	84.57	83.27	13.04	54.64	67.65	91.07
2011 Q4.........	2.0	0.980	88.00	88.00	88.00	86.73	74.59	73.69	66.96	84.57	83.27	15.16	54.64	67.65	91.07
2011 Full Year	2.0	0.980	88.00	88.00	88.50	86.22	75.87	74.98	68.79	84.07	82.78	13.66	54.32	67.26	90.54
2012..............	2.0	0.980	87.25	89.00	88.25	89.29	75.89	74.95	68.33	84.38	83.04	15.68	56.25	68.75	91.96
2013..............	2.0	0.980	86.51	90.00	88.50	90.92	75.10	74.13	67.03	85.01	83.64	17.62	57.28	70.01	92.74
2014..............	2.0	0.980	86.69	92.00	90.50	92.96	76.23	75.23	67.84	86.45	84.59	19.21	58.56	71.58	94.82
2015..............	2.0	0.980	87.92	95.17	93.67	96.19	78.88	77.84	70.23	89.46	87.54	20.79	60.60	74.07	98.12
2016..............	2.0	0.980	88.35	97.55	96.05	98.62	80.87	79.79	72.03	91.72	89.75	21.85	62.13	75.94	100.59
2017..............	2.0	0.980	89.03	100.26	98.76	101.39	83.14	82.02	74.08	94.29	92.26	22.62	63.87	78.07	103.42
2018..............	2.0	0.980	89.44	102.74	101.24	103.92	85.21	84.05	75.95	96.64	94.57	23.14	65.47	80.02	106.00
2019..............	2.0	0.980	90.00	105.45	103.95	106.68	87.48	86.28	78.00	99.22	97.08	23.67	67.21	82.15	108.82
2020..............	2.0	0.980	90.00	107.56	106.06	108.84	89.25	88.01	79.59	101.22	99.04	24.20	68.57	83.80	111.01
2021+............	2.0	0.980	90.00	+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%/yr	+2.0%/yr

Natural Gas and Sulphur Pricing

Year	Henry Hub Nymex Near Month Contract		Midwest Price @ Chicago Then Current $US/ MMbtu	AECO/ NIT Spot Then Current $Cdn/ MMbtu	Alberta Plant Gate					Saskatchewan Plant Gate		Sumas Spot $US/ mmbtu	British Columbia		Sulphur FOB Vancouver $US/LT	Alberta Sulphur at Plant Gas $Cdn/LT
					Spot											
	Constant 2011 $ $US/ MMbtu	Then Current $US/MMbtu			Constant 2011 $ $/MMbtu	Then Current $MMbtu	ARP $/ MMbtu	Aggregator $/MMbtu	Alliance $/MMbtu	SaskEnergy $/MMbtu	Spot $MMbtu		Westcoast Station 2 $/mmbtu	Spot Plant Gate $mmbtu		
2011 Q1	4.35	4.35	4.45	4.03	3.80	3.80	3.76	3.66	3.22	3.66	4.00	4.10	3.83	3.68	140.00	99.86
2011 Q2	4.35	4.35	4.45	4.03	3.80	3.80	3.76	3.66	3.22	3.66	4.00	4.10	3.83	3.68	140.00	99.86
2011 Q3	4.30	4.30	4.40	3.98	3.75	3.75	3.71	3.61	3.17	3.61	3.95	4.05	3.78	3.63	140.00	99.86
2011 Q4	5.00	5.00	5.10	4.59	4.36	4.36	4.31	4.19	3.86	4.21	4.56	4.75	4.39	4.24	140.00	99.86
2011 Full Year	4.50	4.50	4.60	4.16	3.92	3.92	3.89	3.78	3.37	3.79	4.13	4.25	3.96	3.80	140.00	99.86
2012	5.05	5.15	5.25	4.74	4.42	4.51	4.37	4.34	4.00	4.27	4.71	4.85	4.54	4.39	125.00	84.55
2013	5.53	5.75	5.85	5.31	4.87	5.06	4.91	4.88	4.59	4.81	5.28	5.40	5.11	4.95	125.00	84.55

Natural Gas and Sulphur Pricing

Year	Henry Hub Nymex Near Month Contract		Midwest Price @ Chicago Then Current $US/ MMbtu	AECO/ NIT Spot Then Current $Cdn/ MMbtu	Alberta Plant Gate					Saskatchewan Plant Gate		Sumas Spot $US/ mmbtu	British Columbia		Sulphur FOB Vancouver $US/LT	Alberta Sulphur at Plant Gas $Cdn/LT
	Constant 2011 $ $US/ MMbtu	Then Current $US/MMbtu			Spot Constant 2011 $ $/MMbtu	Spot Then Current $MMbtu	ARP $/ MMbtu	Aggregator $/MMbtu	Alliance $/MMbtu	SaskEnergy $/MMbtu	Spot $MMbtu		Westcoast Station 2 $/mmbtu	Spot Plant Gate $mmbtu		
2014	5.89	6.25	6.35	5.77	5.20	5.52	5.35	5.32	5.08	5.25	5.74	5.90	5.57	5.40	100.00	59.04
2015	6.24	6.75	6.85	6.22	5.52	5.97	5.80	5.76	5.57	5.70	6.19	6.40	6.02	5.86	100.00	59.04
2016	6.43	7.10	7.20	6.53	5.69	6.28	6.09	6.05	5.91	5.99	6.50	6.75	6.33	6.16	100.00	59.04
2017	6.50	7.32	7.42	6.76	5.77	6.50	6.31	6.26	6.13	6.21	6.73	6.97	6.56	6.39	102.00	61.08
2018	6.50	7.47	7.57	6.90	5.79	6.65	6.45	6.41	6.27	6.35	6.87	7.12	6.70	6.53	104.04	63.16
2019	6.50	7.62	7.72	7.06	5.80	6.80	6.60	6.55	6.42	6.50	7.03	7.27	6.86	6.69	106.12	65.29
2020	6.50	7.77	7.87	7.21	5.82	6.95	6.75	6.70	6.56	6.65	7.18	7.42	7.01	6.84	108.24	67.45
2021+	6.50	+2.0%/yr	+2.0%/yr	+2.0%/yr	5.82	+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%/yr

Notes:

(1) Pricing assumptions provided by GLJ as used in the GLJ Reserve Report.
(2) Inflation rates used for forecasting prices and costs.
(3) Exchange rates used to generate the benchmark reference prices in this table.

During the year ended December 31, 2010, the Company received the following weighted average prices, excluding the gains and losses on financial instruments, in respect of its production: natural gas – $4.09/Mcf; NGL – $69.06/bbl; and oil – $76.07/bbl. The overall weighted average price received by Tourmaline on an oil equivalent basis was $29.91/Boe.

Additional Information Relating to Reserves Data

The additional information contained in this section pertains to Tourmaline and Exshaw on a consolidated basis and references to Tourmaline include Exshaw (without reduction to reflect the 9.4% third-party minority interest in Exshaw). See "Disclosure of Reserves Data".

Undeveloped Reserves

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to Tourmaline's properties as at the end of the financial years ended December 31, 2010 and 2009.

Proved Undeveloped Reserves

	Light and Medium Crude Oil (Mbbls)		Natural Gas (MMcf)		NGL (Mbbls)		Boe Oil Equivalent (Mbbls)	
Year[1]	**First Attributed[2]**	**Total at Year-end**	**First Attributed**	**Total at Year-end**	**First Attributed**	**Total at Year-end**	**First Attributed**	**Total at Year-end**
2009	716	716	74,099	74,099	847	847	13,913	13,913
2010	2,043	2,711	173,291	234,358	3,934	4,801	34,859	46,572

Notes:

(1) Tourmaline had no reserves as at the end of the financial year ended December 31, 2008.
(2) "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year.

In 2010, proved undeveloped reserves were primarily attributed to drilling locations distributed through the areas of the Alberta Deep Basin. It is anticipated that all of the proved undeveloped locations will be drilled by December 31, 2012.

Probable Undeveloped Reserves

	Light and Medium Crude Oil		Natural Gas		NGL		Boe Oil Equivalent	
	(Mbbls)		(MMcf)		(Mbbls)		(Mbbls)	
Year(1)	First Attributed(2)	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2009	1,669	1,669	77,937	77,937	885	885	15,544	15,544
2010	24	1,623	185,671	259,414	3,228	4,518	34,197	49,377

Notes:

(1) Tourmaline had no reserves as at the end of the financial year ended December 31, 2008.
(2) "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year.

In 2010, probable undeveloped reserves were primarily attributed to drilling locations distributed through the areas of the Alberta Deep Basin. It is anticipated that most of the future development capital associated with the probable undeveloped reserves will be incurred by December 31, 2013.

In general, once proved and/or probable undeveloped reserves are identified, they are scheduled into Tourmaline's development plans. Normally, Tourmaline plans to develop its proved and probable undeveloped reserves within two years. A number of factors that could result in delayed or cancelled development are as follows: changing economic conditions (due to pricing, operating and capital expenditure fluctuations); changing technical conditions (production anomalies such as water breakthrough or accelerated depletion); multi-zone developments (delay of a prospective formation completion until the initial completion is no longer economic); a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and surface access issues (landowners, weather conditions and/or regulatory approvals). See "Risk Factors" and "Industry Conditions".

Significant Factors or Uncertainties

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

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

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

Other than as discussed above and the various risks and uncertainties that participants in the oil and natural gas industry are exposed to generally, Tourmaline is unable to identify any important economic factors or significant uncertainties that will affect any particular components of the reserves data disclosed in this Annual Information Form. See "Risk Factors" and "Industry Conditions".

Future Development Costs

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

Year	Undiscounted Forecast Prices and Costs Proved Reserves	Proved Plus Probable Reserves
2011	387,210	460,061
2012	123,127	261,834
2013	93,450	270,945
2014	5,858	25,457
2015	0	0
2016	0	0
Thereafter	158	158
Total	**609,803**	**1,018,455**

Tourmaline expects that the capital listed in the preceding table will be funded through its existing cash balance, expected cash flow from operations and completed financings.

Other Oil and Natural Gas Information

The additional information contained in this section pertains to Tourmaline and Exshaw on a consolidated basis and references to Tourmaline include Exshaw (without reduction to reflect the 9.4% third-party minority interest in Exshaw).

Crude Oil and Natural Gas Wells

The following table sets forth the number and status of wells in which Tourmaline had a working interest as at December 31, 2010, that Tourmaline considers capable of production.

	Crude Oil Wells(1)				Natural Gas Wells(1)			
	Producing		Non-Producing(2)		Producing		Non-Producing(2)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta(1)	46	45.1	13	10.5	382	242.3	130	88.1
British Columbia(1)	-	-	-	-	25	12.9	25	12.6
Total	**46**	**45.1**	**13**	**10.5**	**407**	**255.2**	**155**	**100.7**

Notes:

(1) All of Tourmaline's wells are located onshore.

(2) The non-producing oil wells and natural gas wells capable of production but which are not currently producing will be re-evaluated with respect to future product prices, proximity to facility infrastructure, design of future exploration and development programs and access to capital,

(3) Includes wells of Exshaw (without reduction to reflect the 9.4% third-party minority interest in Exshaw).

For a general description of Tourmaline's important properties, facilities and installations, see "Description of Core Long-Term Growth Areas".

Properties with no Attributable Reserves

The following table sets out Tourmaline's developed and undeveloped unproved properties as at December 31, 2010, in which Tourmaline has an interest.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	253,341	145,450	914,364	725,796	1,167,705	871,246
British Columbia	22,976	10,877	128,009	55,711	150,985	66,588
Saskatchewan	-	-	73,737	65,754	73,737	65,754
Total(1)	**276,317**	**156,327**	**1,116,110**	**847,261**	**1,392,427**	**1,003,588**

Note:

(1) Includes developed and undeveloped unproved properties of Exshaw (without reduction to reflect the 9.4% third-party minority interest in Exshaw).

The following table sets out Tourmaline's developed and undeveloped unproved properties as at March 23, 2011, in which Tourmaline has an interest.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	257,501	150,152	927,173	746,996	1,184,674	897,148
British Columbia	23,760	11,365	131,755	58,066	155,515	69,431
Saskatchewan	-	-	73,737	65,754	73,737	65,754
Total[1]	**281,261**	**161,517**	**1,132,665**	**870,816**	**1,413,926**	**1,032,333**

Note:

(1) Includes developed and undeveloped unproved properties of Exshaw without reduction to reflect the 9.4% third-party minority interest in Exshaw).

There are no material work commitments in respect of Tourmaline's unproved properties. Tourmaline expects that rights to explore, develop and/or exploit 34,155 net acres (53 net sections) of its undeveloped land holdings will expire by December 31, 2011.

Significant Factors or Uncertainties Relevant to Properties With No Attributed Reserves

See "Additional Information Relating to Reserves Data – Significant Factors or Uncertainties" above.

Additional Information Concerning Abandonment and Reclamation Costs

Tourmaline uses its internal historical costs to estimate its abandonment and reclamation costs when available. The costs are estimated on an area-by-area basis. The industry's historical costs are used when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements. As at December 31, 2010, Tourmaline had 454 net wells for which it expects to eventually incur abandonment and reclamation costs by 2027.

The total abandonment and reclamation costs in respect of proved and probable reserves using forecast prices are $62.0 million (undiscounted) and $16.8 million (discounted at 10%). One hundred percent of such amounts were deducted as abandonment and reclamation costs in estimating Tourmaline's future net revenue in respect of proved and probable reserves as disclosed above.

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

Forecast Prices and Costs (Total Proved plus Probable) (000s)

Year	**Abandonment and Reclamation Costs (Undiscounted)**	**Abandonment and Reclamation Costs (Discounted at 10%)**
2011	12,086	11,510
2012	41	35
2013	123	97
Thereafter	49,744	5,113
Total	**61,994**	**16,755**

Tourmaline expects to pay approximately $1.0 million in the next three financial years in respect of its abandonment and reclamation costs,

Tax Horizon

Tourmaline has no current tax expense and, based on current reserve forecasts, will be able to realize the benefit of its non-capital losses and expects to remain non-taxable through at least 2014. Tourmaline has estimated approximately $1,561 million of tax pools will be available as at December 31, 2011, which can be used to offset taxable income in future years.

Capital Expenditures

The following table summarizes capital expenditures (including corporate acquisitions and capitalized general administrative expenses) related to Tourmaline's activities for the year ended December 31, 2010:

	$000's
Exploration, drilling and completions	353,536
Development, equipping and facilities	64,488
Property and corporate acquisitions(1)	321,743
Equipment and facilities	64,089
Geological and geophysical	5,234
Other (including capitalized G&A)	6,805
Total(2)	**815,895**

Notes:

(1) Approximately $195.5 million of the property acquisition expenditures were for proved properties and approximately $123.1 million of the property acquisition expenditures were for unproved properties.

(2) Includes capital expenditures related to Exshaw (without reduction to reflect the 9.4% third-party minority interest in Exshaw).

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which Tourmaline participated in the year ended December 31, 2010:

	Exploratory Wells		**Development Wells**	
	Gross	**Net**	**Gross**	**Net**
Natural Gas	22	19.3	50	32.1
Oil	2	2.0	5	4.4
Service	-	-	-	-
Dry	-	-	-	-
Total(1)	**24**	**21.3**	**55**	**36.5**

Note:

(1) Includes wells in which Exshaw participated (without reduction to reflect the 9.4% third-party minority interest in Exshaw).

See "Description of Core Long-Term Growth Areas" and "Description of the Business" for a description of Tourmaline's exploration and development plans.

Production Estimates

The following table sets out the volume of Tourmaline's production estimated for the year ended December 31, 2011 as evaluated by GLJ and AJM, which is reflected in the estimate of future net revenue disclosed in the tables contained under "Disclosure of Reserves Data" above.

	Light and Medium Crude Oil		**Natural Gas**		**NGL**		**Total**	
Reserves Category	**Company Gross (bbl/d)**	**Company Net (bbl/d)**	**Company Gross (Mcf/d)**	**Company Net (Mcf/d)**	**Company Gross (bbl/d)**	**Company Net (bbl/d)**	**Company Gross (Boe/d)**	**Company Net (Boe/d)**
Proved	**1,752**	**1,530**	**177,738**	**161,886**	**2,516**	**2,116**	**33,891**	**30,627**
Proved Plus Probable	**1,997**	**1,725**	**194,993**	**177,738**	**2,861**	**2,433**	**37,356**	**33,781**

Notes:

(1) No one field accounted for 20 percent or more of Tourmaline's estimated 2011 production in the Consolidated Reserve Report.

(2) Numbers may not add due to rounding.

(3) Includes Exshaw production (without reduction to reflect the 9.4% third-party minority interest in Exshaw).

Production History

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

	Quarter Ended 2010[4]			
	December 31	**September 30**	**June 30**	**March 31**
Average Daily Production[1]				
Light and Medium Crude Oil (Bbl/d)	1,782	1,249	1,608	1,213
Natural Gas (Mcf/d)	122,294	103,286	95,533	60,545
NGL (Bbls/d)	789	360	357	321
Combined (Boe/d)	22,953	18,823	17,887	11,625
Average Price Received				
Light and Medium Crude Oil (S/bbl)	79.47	71.71	74.06	79.65
Natural Gas ($/Mcf)	4.17	4.34	4.61	5.41
NGL ($/bbl)	67.96	71.45	65.43	73.17
Combined ($/Boe)	30.74	29.94	32.58	38.53
Royalties Paid				
Light and Medium Crude Oil ($/bbl)	9.45	12.21	10.40	13.89
Natural Gas ($/Mcf)	(0.06)	0.25	0.10	0.50
NGL ($/bbl)	10.78	31.30	36.31	46.58
Combined ($/Boe)	0.77	2.80	2.19	5.35
Production Costs (includes transportation)				
Light and Medium Crude Oil ($/bbl)	12.01	14.22	8.98	11.95
Natural Gas ($/Mcf)	1.15	1.26	1.42	1.45
NGL ($/bbl)[2]	-	-	-	-
Combined ($/Boe)	7.31	8.02	8.57	9.03
Netback Received ($/Boe)[3]	22.66	19.12	21.82	24.16

Notes:

(1) Before deduction of royalties.
(2) NGL volumes are derived from natural gas production, as such all the related operating costs are attributed to the production of natural gas.
(3) Netbacks are calculated by subtracting royalties and operating costs from revenues.
(4) Includes Exshaw (without reduction to reflect the 9.4% third-party minority interest in Exshaw).

The following table sets forth the average daily production volumes for the year ended December 31, 2010 for each of the important fields comprising Tourmaline's assets.

	Light and Medium Crude Oil (Bbls/d)	**Natural Gas (Mcf/d)**	**NGL (Bbls/d)**	**Boe (Boe/d)**
Alberta Deep Basin	616	71,997	363	12,979
Other Alberta properties	719	9,681	17	2,349
British Columbia properties	129	13,927	78	2,528
Total[1]	**1,464**	**95,605**	**458**	**17,856**

Note:

(1) Includes Exshaw (without reduction to reflect the 9.4% third-party minority interest in Exshaw).

For the year ended December 31, 2010, approximately 75% of Tourmaline's gross revenue was derived from natural gas production and approximately 25% was derived from crude oil and NGL production.

Forward Contracts and Marketing

Other than the following, Tourmaline is not bound by any agreement (including any transportation agreement), directly or through an aggregator, under which it is precluded from fully realizing, or may be protected from the full effect of, future market prices for crude oil or natural gas.

The Company's commodity hedging policy has been established with the Board of Directors authorizing management to hedge up to 50% of current production. For the fourth quarter of 2010, Tourmaline produced 122.3

MMcf/d. In the first quarter of 2011, an average of 29.4 (24%) MMcf/d is sold forward at an average fixed price of $5.95 per Mcf. For the full year 2011, an average of 23.0 (19%) MMcf/d is sold forward at an average fixed price of $5.82 per Mcf. In a similar manner, an average of 4.6 (4%) MMcf/d is sold forward at an average fixed price of $5.65 per Mcf for 2012.

Forward sales of crude oil at fixed prices constitute less than 4% of the Company's fourth quarter 2010 oil and NGL production.

In addition, Tourmaline's transportation obligations or commitments for future physical deliveries of crude oil and natural gas do not exceed Tourmaline's expected related future production from its proved reserves, estimated using forecast prices and costs, as disclosed in this Annual Information Form.

OTHER BUSINESS INFORMATION

Specialized Skill and Knowledge

Tourmaline employs individuals with various professional skills in the course of pursuing its business plan. These professional skills include, but are not limited to, geology, geophysics, engineering, financial and business skills, which are widely available in the industry. Drawing on significant experience in the oil and gas business, Tourmaline believes its management team has a demonstrated track record of bringing together all of the key components to a successful exploration and production company: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows Tourmaline to effectively identify, evaluate and execute on value added initiatives.

Competitive Conditions

The oil and natural gas industry is very competitive. The Canadian Association of Petroleum Producers estimates that there are over 1,000 exploration and production companies in Canada. Tourmaline controls less than one percent of the business in western Canada, but where it is active (see "Description of Core Long-Term Growth Areas"), Tourmaline believes it has a strong competitive position.

Companies operating in the petroleum industry must manage risks which are beyond the direct control of company personnel. Among these risks are those associated with exploration, environmental damage, commodity prices, foreign exchange rates and interest rates.

The oil and natural gas industry is intensely competitive and Tourmaline competes with a substantial number of other entities, many of which have greater technical or financial resources. With the maturing nature of the WCSB, the access to new prospects is becoming more competitive and complex.

Tourmaline attempts to enhance its competitive position by operating in areas where it believes its technical personnel are able to reduce some of the risks associated with exploration, production and marketing because they are familiar with the areas of operation. Management believes that Tourmaline will be able to explore for and develop new production and reserves with the objective of increasing its cash flow and reserve base. See "Risk Factors – Competition".

Cycles

The Company's business is generally not cyclical. The exploration for and the development of oil and natural gas reserves is dependent on access to areas where drilling is to be conducted. Seasonal weather variation, including "freeze-up" and "break-up", affect access in certain circumstances. See "Risk Factors – Seasonality".

Environmental Protection

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation may require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on earnings and overall competitiveness of the Company. For a description of the financial and operational effects of environmental protection requirements on the capital expenditures, earnings and competitive position of Tourmaline see "Industry Conditions – Environmental Regulation" and "Risk Factors – Environmental".

Employees

At December 31, 2010, Tourmaline had 70 full time employees and seven consultants located at its Calgary office, and 14 full time employees and 29 contract operators in various field locations. Tourmaline currently has 72 full time employees and seven consultants located at its Calgary office, and 17 full time employees and 34 contract operators in various field locations.

Reorganizations

Other than disclosed under "General Development of the Business", Tourmaline has not completed any material reorganization within the three most recently completed financial years or completed during the current financial year. No material reorganization is currently proposed for the current financial year. See "General Development of the Business".

Environmental, Health and Safety Policies

The Company supports environmental protection and employee health and safety by integrating the essential principles and practices through its environmental management systems and employee occupational health and safety programs. The Company promotes safety and environmental awareness and protection through the implementation and communication of the Company's environmental management and employee occupational health and safety programs policies and procedures. Committee structures are established in the Company's operations which are designed to allow for employee participation and development of policies and programs which provide employees with job orientation, training, instruction and supervision to assist them in conducting their activities in an environmentally responsible and safe manner.

The Company develops emergency response teams and preparedness plans in conjunction with local authorities, emergency services and the communities in which it operates in order to effectively respond to an environmental incident should it arise. Environmental assessments are undertaken for new projects or when acquiring new properties or facilities in order to identify, assess and minimize environmental risks and operational exposures. The Company conducts audits of operations to confirm compliance with internal standards and to stimulate improvement in practices where needed. Documentation is maintained to support internal accountability and measure operational performance against recognized industry indicators to assist in achieving the objectives of the described policies and programs.

The Company also faces environmental, health and safety risks in the normal course of its operations due to the handling and storage of hazardous substances. The Company's environmental and occupational health and safety management systems are designed to manage such risks in the Company's business and allow action to be taken to mitigate the extent of any environmental, health or safety impacts from such operations. A key aspect of these systems is the performance of annual environmental and occupational health and safety audits.

DIVIDENDS

The Company has never declared or paid any cash dividends on the Common Shares. The Company currently intends to retain future earnings, if any, for future operations, expansion and debt repayment. Any decision to declare and pay dividends will be made at the discretion of the Board of Directors and will depend on, among other things, the Company's results of operations, current and anticipated cash requirements and surplus, financial condition, contractual restrictions and financing agreement covenants, solvency tests imposed by corporate law and other factors that the Board may deem relevant.

In addition to the foregoing, the Company's ability to pay dividends now or in the future may be limited by covenants contained in the agreements governing any indebtedness that the Company has incurred or may incur in the future including the terms of the Company's credit facilities. Tourmaline's credit facility prohibits Tourmaline from declaring or paying any dividends (excluding stock dividends) to any of its shareholders or returning any capital (including by way of dividend) to any of its shareholders.

DESCRIPTION OF CAPITAL STRUCTURE

General Description of Capital Structure

The authorized share capital of Tourmaline consists of an unlimited number of Common Shares and an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares.

The following is a summary of the rights, privileges, restrictions and conditions attaching to the shares in Tourmaline's share capital.

Common Shares

Tourmaline is authorized to issue an unlimited number of Common Shares without nominal or par value. Holders of Common Shares are entitled to one vote per share at meetings of shareholders of Tourmaline. Subject to the rights of the holders of First Preferred Shares and Second Preferred Shares and any other shares having priority over the Common Shares, holders of Common Shares are entitled to dividends if, as and when declared by the Board of Directors and upon liquidation, dissolution or winding-up to receive the remaining property of Tourmaline.

First Preferred Shares

The First Preferred Shares are issuable in series and will have such rights, restrictions, conditions and limitations as the Board of Directors may from time to time determine. No First Preferred Shares have been issued.

Tourmaline is authorized to issue an unlimited number of First Preferred Shares without nominal or par value. Holders of First Preferred Shares are entitled to receive dividends if, as and when declared by the Board of Directors, in priority to holders of Common Shares and Second Preferred Shares. In the event of a liquidation, dissolution or winding-up of Tourmaline, holders of the First Preferred Shares are entitled to receive a rateable share of all distributions made in priority to the holders of the Common Shares and Second Preferred Shares.

Second Preferred Shares

The Second Preferred Shares are issuable in series and will have such rights, restrictions, conditions and limitations as the Board of Directors may from time to time determine. No Second Preferred Shares have been issued.

Tourmaline is authorized to issue an unlimited number of Second Preferred Shares without nominal or par value. Holders of Second Preferred Shares are entitled to receive dividends if, as and when declared by the Board of Directors subject to the preference of First Preferred Shares but in priority to holders of Common Shares. In the event of a liquidation, dissolution or winding-up of Tourmaline, holders of the Second Preferred Shares are entitled to receive a rateable share of all distributions made, subject to the preference of holders of First Preferred Shares but in priority to holders of Common Shares.

Constraints

There are currently no constraints imposed on the ownership of securities of the Company to ensure that Tourmaline has a required level of Canadian ownership.

Ratings

Tourmaline has not asked for and received a stability rating, or to the knowledge of Tourmaline, has received any other kind of rating, including, a provisional rating, from one or more approved rating organizations for securities of Tourmaline that are outstanding and which continue in effect.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares trade on the Toronto Stock Exchange (the "**TSX**") under the symbol TOU. The following table sets forth the price ranges and volume traded on the TSX on a monthly basis for each month of the most recently completed financial year:

	Common Shares		
	Price Range		
	High ($/share)	**Low ($/share)**	**Trading Volume**
2010			
November 23-30	21.26	20.10	5,371,812
December	22.00	20.05	9,076,396

Prior Sales

The following table provides details regarding each class of securities of the Company that are outstanding but not listed or quoted on a market place that have been issued by the Company during the most recently completed financial year.

Options Granted During 2010

Date of Issuance	**Number of Options**	**Exercise Price of Options**
November 30, 2010	225,000	$20.68
September 15, 2010	1,845,000	$18.35
July 1, 2010	252,000	$18.20
May 1, 2010	95,000	$18.00
April 1, 2010	330,000	$18.00
February 15, 2010	170,000	$16.68
January 1, 2010	490,000	$15.00

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the Company's knowledge, as of December 31, 2010, no securities of Tourmaline are held in escrow or subject to a contractual restriction on transfer.

DIRECTORS AND OFFICERS

Name, Occupation and Security Holding

The names, province or state, and country of residence, positions and offices held with the Company, and principal occupation of the directors and executive officers of the Company are set out below and, in the case of directors, the period each has served as a director of the Company.

Name, Province and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director Since
Michael L. Rose Alberta, Canada	Chairman, President and Chief Executive Officer	Chairman, President and Chief Executive Officer of Tourmaline since August 2008. Prior thereto, Chairman, President and Chief Executive Officer of Duvernay, an oil and gas company.	August 6, 2008
William D. Armstrong(4)(5) Colorado, United States	Director	President and Chief Executive Officer of Armstrong Oil & Gas Inc., an oil and gas exploration and production company.	October 27, 2008
Lee Baker(3)(4)(5) Alberta, Canada	Director	President and Chief Executive Officer of Nordegg Resources Inc., an oil and gas company, since March 2008. Prior thereto, President and Chief Executive Officer of RSX Energy Inc., an oil and gas company.	March 22, 2011
Robert W. Blakely(1)(2)(3)(5) Ontario, Canada	Director	President of Likrilyn Capital Corporation, an investment management company.	October 27, 2008
Kevin Keenan(4) Alberta, Canada	Director	Independent businessman since November 2009. Prior thereto, Vice President, Operations and Chief Operating Officer of Exshaw. Prior thereto, President of Manor House Venture Partners Inc.	October 27, 2008
Phillip A. Lamoreaux(1)(2)(3)(4)(5) California, United States	Director	Managing Member of Lamoreaux Capital Management LLC, an investment management company.	September 9, 2010
Andrew B. MacDonald(1)(2)(5) British Columbia, Canada	Director	Independent business man since June 2009. Prior thereto, Co-Head of Canadian Equities and Portfolio Manager with Phillips, Hager & North Investment Management, an investment management company.	March 22, 2011
Clayton H. Riddell Alberta, Canada	Director	Chairman and Chief Executive Officer of Paramount Resources Ltd., an oil and gas company.	October 27, 2008
Brian G. Robinson Alberta, Canada	Director and Vice President, Finance and Chief Financial Officer	Director and Vice President, Finance and Chief Financial Officer of Tourmaline since August 2008. Prior thereto, Vice President, Finance and Chief Financial Officer of Duvernay.	October 27, 2008
Robert N. Yurkovich(6) Alberta, Canada	Director and Executive Vice President, Exploration	Director and Executive Vice President, Exploration of Tourmaline since October 2008. Prior thereto, Vice President, Exploration of Duvernay.	October 27, 2008
Stanley Nowek Alberta, Canada	Vice President, Operations and Chief Operating Officer	Vice President, Operations and Chief Operating Officer of Tourmaline since October 2008. Prior thereto, Vice President, Operations and Chief Operating Officer of Duvernay.	N/A
Ronald J. Hill Alberta, Canada	Vice President, Exploration	Vice President, Exploration of Tourmaline since November 2009. Prior thereto, Senior Geologist at Tourmaline and Duvernay.	N/A
Drew E. Tumbach Alberta, Canada	Vice President, Land and Contracts	Vice President, Land and Contracts of Tourmaline since October 2008. Prior thereto, Vice President, Land and Contracts of Duvernay.	N/A
W. Scott Kirker Alberta, Canada	Secretary and General Counsel	Secretary and General Counsel of Tourmaline since August 2008. Prior thereto, Manager Corporate Affairs of Duvernay.	N/A

Notes:

(1) Member of the Audit Committee. Mr. Blakely is the Chairman of the Audit Committee.
(2) Member of the Compensation Committee. Mr. Blakely is the Chairman of the Compensation Committee.
(3) Member of the Corporate Governance Committee. Mr. Lamoreaux is the Chairman of the Corporate Governance Committee.
(4) Member of the Reserves, Safety and Environmental Committee. Mr. Keenan is the Chairman of the Reserves, Safety and Environmental Committee.
(5) Independent director.
(6) Mr. Yurkovich is part time in his capacity as Executive Vice President, Exploration.

All of the Company's directors' terms of office will expire at the earliest of their resignation, the close of the next annual shareholder meeting called for the election of directors, or on such other date as they may be removed according to the ABCA. Each director will devote the amount of time as is required to fulfill his obligations to the Company. The Company's officers are appointed by and serve at the discretion of the Board of Directors.

As of the date of this Annual Information Form, the directors and executive officers of Tourmaline, as a group, beneficially owned, or controlled or directed, directly or indirectly, 33,573,142 Common Shares or approximately 24.3% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

To the knowledge of the Company, except as described below, no director or executive officer of the Company (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within 10 years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including the Company), that: (a) was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**"), that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Mr. Clayton Riddell is a director and executive officer of Paramount Resources Ltd. ("**Paramount**"). From 1992 to 2008, Paramount was the general partner of T.T.Y. Paramount Partnership No. 5 ("**TTY**"), a limited partnership, which was an unlisted reporting issuer in certain provinces of Canada. TTY was established in 1980 to conduct oil and gas exploration and development but had not carried on active operations since 1984 and had only nominal assets. A cease trade order against TTY was issued by the Autorité des marches financiers in 1999 for failing to file the June 30, 1998 interim financial statements in Québec. The cease trade order was revoked on April 9, 2008. TTY was dissolved on July 21, 2008.

Bankruptcies

To the knowledge of the Company, no director or executive officer of the Company (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company: (a) is, as of the date of this Annual Information Form, or has been within the 10 years before the date of this Annual Information Form, a director or executive officer of any company (including the Company) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the 10 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.

Penalties or Sanctions

To the knowledge of the Company, no director or executive officer of the Company (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company, has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Certain officers and directors of the Company are also officers and/or directors of other entities engaged in the oil and gas business generally. As a result, situations may arise where the interest of such directors and officers conflict with their interests as directors and officers of other companies. The resolution of such conflicts is governed by applicable corporate laws, which require that directors act honestly, in good faith and with a view to the best interests of the Company. Conflicts, if any, will be handled in a manner consistent with the procedures and remedies set forth in the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

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

Regulatory Actions

There are no:

(a) penalties or sanctions imposed against Tourmaline by a court relating to securities legislation or by a securities regulatory authority during Tourmaline's financial year;

(b) other penalties or sanctions imposed by a court or regulatory body against Tourmaline that would likely be considered important to a reasonable investor in making an investment decision; and

(c) settlement agreements Tourmaline entered into before a court relating to securities legislation or with a securities regulatory authority during Tourmaline's financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There is no material interest, direct or indirect, of any: (a) director or executive officer of Tourmaline; (b) person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of Tourmaline's voting securities; and (c) associate or affiliate of any of the persons or companies referred to in (a) or (b) above in any transaction since the Company's incorporation in 2008 that has materially affected or is reasonably expected to materially affect Tourmaline other than that Messrs. Rose and Keenan, directors of Tourmaline, were directors and shareholders, and Mr. Keenan was also an officer, of Exshaw at the time of the Company's acquisition of Exshaw.

AUDITOR, TRANSFER AGENT AND REGISTRAR

The Company's auditors are KPMG LLP, Chartered Accountants, Suite 2700, 205 – 5th Avenue S.W., Calgary, Alberta T2P 4B9.

The transfer agent and registrar for the Common Shares is Canadian Stock Transfer Company, Inc. at its principal offices in Calgary, Alberta and Toronto, Ontario.

MATERIAL CONTRACTS

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

INTERESTS OF EXPERTS

Names of Experts

The only persons or companies who are named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made by the Company under National Instrument 51-102 during, or relating to the Company's most recently completed financial year and whose profession or business gives authority to such report, valuation, statement or opinion, are:

- KPMG LLP, Tourmaline's independent auditors; and
- GLJ and AJM, Tourmaline's independent reserve evaluators (collectively, the "**Reserve Evaluators**").

Interests of Experts

To the Company's knowledge, no registered or beneficial interests, direct or indirect, in any securities or other property of the Company or of one of the Company's associates or affiliates (i) were held by any of the Reserve Evaluators or by the "designated professionals" (as defined in Form 51-102F2) of the Reserve Evaluators, when the Reserve Evaluators prepared their respective reports, valuations, statements or opinions referred to herein as having been prepared by such Reserve Evaluators, (ii) were received by any of the Reserve Evaluators or the designated professionals of the Reserve Evaluators after such Reserve Evaluator prepared the report, valuation, statement or opinion in question, or (iii) is to be received by any of the Reserve Evaluators or the designated professionals of the Reserve Evaluators.

None of the Reserve Evaluators nor any director, officer or employee of any of the Reserve Evaluators is or is expected to be elected, appointed or employed as a director, officer or employee of the Company or of any associate or affiliate of the Company.

KPMG LLP has advised the Company that they are independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta and British Columbia, all of which should be carefully considered by investors in the oil and natural gas industry. It is not expected that any of these regulations or controls will affect the Company's operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and natural gas industry.

Pricing and Marketing

Crude Oil

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

Natural Gas

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

The governments of Alberta and British Columbia also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

Pipeline Capacity

As a result of pipeline expansions over the past several years, there is ample pipeline capacity to accommodate current production levels of oil and natural gas in western Canada and pipeline capacity does not generally limit the ability to produce and market such production.

The North American Free Trade Agreement

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

NAFTA prohibits discriminatory border restrictions and export taxes. NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

Alberta

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

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" ("**NRF**") containing the Government's proposals for Alberta's new royalty regime which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors, which changes included a decrease in the maximum royalty rates for conventional oil and natural gas production effective for the January 2011 production month. Royalty curves incorporating the changes announced on March 11, 2010 were released on May 27, 2010. Alberta royalties in effect after December 31, 2010 are known as the "Alberta Royalty Framework" ("**ARF**").

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure which classified oil based on the date of discovery of the pool. Under the ARF, royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and market prices. Royalty rates for conventional oil under the NRF ranged from 0-50%, an increase from the previous maximum rates of 30-35% depending on the vintage of the oil, and rate caps were set at $120 per barrel. Effective January 1, 2011, the maximum royalty payable under the ARF was reduced to 40%. 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 $535/m^3 compared to the previous royalty curve.

Royalty rates for natural gas under the ARF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF ranged from 5-50%, an increase from the previous maximum rates of 5-35%, and rate caps were set at $16.59/GJ. Effective January 1, 2011, the maximum royalty payable under the ARF was reduced to 36%. 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.

Oil sands projects are also subject to the ARF. Prior to payout, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil and Cushing, Oklahoma: rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1-9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher. An oil sands project reaches payout when its cumulative revenue exceeds its cumulative costs. Costs include specified allowed capital and operating costs related to the project plus a specified return allowance. As part of the implementation of the NRF, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the NRF or the ARF.

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.

In April 2005, the Government of Alberta implemented the Innovative Energy Technologies Program (the "**IETP**"), which has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP is backed by a $200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and 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 a $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 spudded subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 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 5-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 m) 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 NRF. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers were only able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that had already elected to adopt such rates as of that date were permitted to switch to Alberta's conventional royalty structure until February 15, 2011. On January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to the ARF. 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. The program introduced a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program, both applying to conventional oil or natural gas wells drilled between April 1, 2009 and March 31, 2010. The drilling royalty credit provides up to a $200 per metre royalty credit for new wells and is primarily expected to benefit smaller producers since the maximum credit available will be determined using the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010, favouring smaller producers with lower activity levels. The new well incentive program initially applied to wells that began producing conventional oil or natural gas between April 1, 2009 and March 31, 2010 and provided for a maximum 5% royalty rate for the first 12 months of production on a maximum of 50,000 barrels of oil or 500 MMcf of natural gas. In June, 2009, the Government of Alberta announced the extension of these two incentive programs for one year to March 31, 2011. On March 11, 2010, the Government of Alberta announced that the incentive program rate of 5% for the first 12 months of production would be made permanent, with the same volume limitations.

In addition to the foregoing, on May 27, 2010, in conjunction with the release of the new royalty curves, the Government of Alberta announced a number of new initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;
- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;
- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010;
- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

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

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 ("**old oil**"), between October 31, 1975 and June 1, 1998 ("**new oil**"), or after June 1, 1998 ("**third-tier oil**"). The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

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

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

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

- *Summer Royalty Credit Program* providing a royalty credit of 10% of drilling and completion costs up to $100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;

- *Deep Royalty Credit Program* providing a royalty credit equal to approximately 23% of drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 2,300 metres spudded between December 1, 2003 and September 1, 2009;

- *Deep Re-Entry Royalty Credit Program* providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres and a re-entry date subsequent to December 1, 2003;

- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation with a spud date after November 30, 2003;

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

- *Marginal Royalty Reduction Program* providing royalty breaks for low productivity natural gas wells with average monthly production under 25,000 m^3 during the first 12 production months and average daily production less than 23 m^3 for every metre of marginal well depth;

- *Ultra-Marginal Royalty Reduction Program* providing additional royalty reductions for low productivity shallow natural gas wells with a true vertical depth of less than 2,300 metres, average monthly production under 60,000 m^3 during the first 12 production months and average daily production less than 11.5 m^3 (development wells) or 17 m^3 (exploratory wildcat wells) for every 100 metres of marginal well depth;

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

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

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. In both 2009 and 2010, the Government of British Columbia allocated $120 million in royalty credits for oil and gas companies under the Infrastructure Royalty Credit Program.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. Natural gas wells spudded within the 10-month period from September 1, 2009 to June 30, 2010 and brought on production by December 31, 2010 qualify for a 2% royalty rate for the first 12 months of production, beginning from the first month of production for the well (the "**Royalty Relief Program**"). British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 metres. Wells spudded between September 1, 2009 and June 30, 2010 may qualify for both the Royalty Relief Program and the Deep Royalty Credit Program but will only receive the benefits of one program at a time. An additional $50 million was also allocated to be distributed through the Infrastructure Royalty Credit Program to stimulate investment in oilfield-related road and pipeline construction.

Land Tenure

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

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

In Alberta, the NRF includes a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. The order in which these agreements will receive the reversion notice will depend on their vintage and location, with the older leases and licenses receiving reversion notices first beginning in January 2011. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

In December, 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009, providing the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and are binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the

ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment. Although no regional plans have been established under the ALSA, the planning process is underway for the Lower Athabasca Region (which contains the majority of oil sands development) and the South Saskatchewan Region. While the potential impact of the regional plans established under the ALSA cannot yet be determined, it is clear that such regional plans may have a significant impact on land use in Alberta and may affect the oil and gas industry.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"), which requires a reduction in greenhouse gas ("**GHG**") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 and commits Canada to reduce its GHG emissions levels to 6% below 1990 "business-as-usual" levels by 2012.

On February 14, 2007, the House of Commons passed Bill C-288, *An Act to ensure Canada meets its global climate change obligations under the Kyoto Protocol*. The resulting *Kyoto Protocol Implementation Act* came into force on June 22, 2007. Its stated purpose is to "ensure that Canada takes effective and timely action to meet its obligations under the Kyoto Protocol and help address the problem of global climate change." It requires the federal Minister of the Environment to, among other things, produce an annual climate change plan detailing the measures to be taken to ensure Canada meets its obligations under the Kyoto Protocol. It also authorizes the establishment of regulations respecting matters such as emissions limits, monitoring, trading and enforcement.

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

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("**CCS**") technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO_2 equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors governed by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets: Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at $15 per tonne of CO_2 equivalent for the 2010 to 12 period, rising to $20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce GHG emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either purchase the offset credits for cancellation or banking for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol which facilitates investment by developed nations in emissions-reduction projects in developing countries. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

The United Nations Framework Convention on Climate Change is working towards establishing a successor to the Kyoto Protocol. From December 7 to 18, 2009, a meeting between government leaders and representatives from approximately 170 countries in Copenhagen, Denmark (the "**Copenhagen Conference**") resulted in the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. From November 29 to December 10, 2010, a meeting between representatives from approximately 190 countries in Cancun, Mexico resulted in the Cancun Agreements, in which developed countries committed to additional measures to help developing countries deal with climate change. Unlike the Kyoto Protocol, however, neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets.

In response to the Copenhagen Accord, the Government of Canada indicated on January 29, 2010 that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020. This goal is similar to the goal expressed in previous policy documents which were discussed above.

Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations have been proposed to date. Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent, if any, the proposals contained in the Updated Action Plan will be implemented.

On December 23, 2010, the United States Environmental Protection Agency indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by July, 2011 and for refineries by December, 2011.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on December 4, 2003, amending it through the *Climate Change and Emissions Management Amendment Act* which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to gross domestic product by 2020.

Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Similar to the Updated Action Plan, the CCEMA and the associated Specified Gas Emitters Regulation make a distinction between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity to 88% of their baseline for 2008 and subsequent years, with their baseline being established by the average of the ratio of the total annual emissions to production for the years 2003 to 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the Specified Gas Emitters Regulation. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of baseline in the fifth year, 6% of baseline in the sixth year, 8% of baseline in the seventh year, and 10% of baseline in the eighth year. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA contains compliance mechanisms that are similar to the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of $15 per tonne of CO_2 equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta. Unlike the Updated Action Plan, the CCEMA does not contemplate a linkage to external compliance mechanisms such as the Kyoto Protocol's Clean Development Mechanism.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, which deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

British Columbia

In February, 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The initial level of the tax was set at $10 per tonne of CO_2 equivalent and rose to $15 per tonne of CO_2 equivalent on July 1, 2009 and $20 per tonne of CO_2 equivalent on July 1, 2010. It is scheduled to further increase at a rate of $5 per tonne of CO_2 equivalent on July 1 of every year until it reaches $30 per tonne of CO_2 equivalent on July 31, 2012. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**") which received royal assent on May 29, 2008 and will come into force by regulation of the Lieutenant Governor in Council. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. It is expected that GHG emissions restrictions will be applied to facilities emitting more than 25,000 tonnes of CO_2 equivalents per year, which will be required to meet established targets through a combination of emissions allowances issued by the Government of British Columbia and the purchase of emissions offsets generated through activities that result in a reduction in GHG emissions. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations came into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO_2 equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO_2 equivalents per year are required to have their emissions reports verified by a third party.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Company's other public filings before making an investment decision.

Exploration, Development and Production Risks

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

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

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

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and continued in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and 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 caused the broader credit markets to further deteriorate and stock markets to decline substantially. Although economic conditions improved towards the latter portion of 2009 and in 2010, as anticipated, the recovery from the recession has been slow in various jurisdictions including in Europe and the United States and has been impacted by various ongoing factors including sovereign debt levels and high levels of unemployment which continue to impact commodity prices and to result in high volatility in the stock market.

Prices, Markets and Marketing

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

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

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

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Operational Dependence

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

Project Risks

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

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

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

Competition

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

Regulatory

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

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge. Although the Company believes that it will be in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Climate Change

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. The Company's exploration and production facilities and other operations and activities emit greenhouse gases and require the Company to comply with greenhouse gas emissions legislation in Alberta and British Columbia or that may be enacted in other provinces. The Company may also be required comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which is now expected to be modified to ensure consistency with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits required by the Kyoto Protocol, the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Company. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Company and its operations and financial condition. See "Industry Conditions – Climate Change Regulation".

Variations in Foreign Exchange Rates and Interest Rates

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

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

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

Substantial Capital Requirements

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

Additional Funding Requirements

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

Issuance of Debt

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

Hedging

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

Availability of Drilling Equipment and Access

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

Title to Assets

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

Reserve Estimates

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

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

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

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

Insurance

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

Geopolitical Risks

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

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

Dilution

The Company may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Company which may be dilutive. In addition, existing shareholders of the Company may in the future wish to reduce their share position in the Company and sell some or all of their shares. The sale of a substantial number of the Common Shares in the public market, or the perception that such sales may occur, could adversely affect the prevailing market price of the Common Shares and negatively impact the Company's ability to raise equity capital in the future.

Management of Growth

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

Expiration of Licences and Leases

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

Dividends

The Company has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Company, the need for funds to finance ongoing operations and other considerations as the board of directors of the Company considers relevant.

Aboriginal Claims

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

Seasonality

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

Third Party Credit Risk

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

Reliance on Key Personnel

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

Certain Forward-Looking Information May Prove Inaccurate

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

Share Price Volatility

The market price for Common Shares may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond the Company's control, including the following: (i) actual or anticipated fluctuations in the Company's quarterly results of operations; (ii) actual or anticipated changes in oil and natural gas prices; (iii) recommendations by securities research analysts; (iv) changes in the economic performance or market valuations of other companies that investors deem comparable to the Company; (v) addition or departure of the Company's executive officers and other key personnel; (ii) sales or perceived sales of additional Common

Shares; (vii) significant acquisitions or business combinations, strategic partnerships, joint ventures or capital commitments by or involving the Company or its competitors; and (viii) news reports relating to trends, concerns, technological or competitive developments, regulatory changes and other related issues in the Company's industry or target markets.

Financial markets have experienced significant price and volume fluctuations in the last several years that have particularly affected the market prices of equity securities of companies and that have, in many cases, been unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of the Common Shares may decline even if the Company's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause decreases in asset values that are deemed to be other than temporary, which may result in impairment losses. As well, certain institutional investors may base their investment decisions on consideration of the Company's environmental, governance and social practices and performance against such institutions' respective investment guidelines and criteria, and failure to meet such criteria may result in a limited or no investment in the Common Shares by those institutions, which could adversely affect the trading price of the Common Shares. There can be no assurance that continuing fluctuations in the price and volume of publicly traded equity securities will not occur. If such increased levels of volatility and market turmoil continue, the Company's operations could be adversely impacted and the trading price of the Common Shares may be adversely affected.

Conflicts of Interest

Certain directors of the Company are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "Directors and Officers – Conflicts of Interest".

Changes to Accounting Policies, including the Implementation of IFRS

International Financial Reporting Standards ("**IFRS**") replaced Canadian generally accepted accounting principles ("**Canadian GAAP**") in 2011 for Canadian publicly accountable enterprises. While IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences that must be evaluated. The implementation of IFRS may result in significant adjustments to the Company's financial results, which could negatively impact the Company's business, including increasing the risk of failing a financial covenant contained within the Credit Facilities.

Future Acquisition Activities May Have Adverse Effects

The acquisition of oil and natural gas companies and assets is subject to substantial risks, including the failure to identify material problems during due diligence, the risk of over-paying for assets and the inability to arrange financing for an acquisition as may be required or desired. Further, the integration and consolidation of acquisitions requires substantial human, financial and other resources and, ultimately, the Company's acquisitions may not be successfully integrated. There can be no assurances that any future acquisitions will perform as expected or that the returns from such acquisitions will support the indebtedness incurred to acquire them or the capital expenditures needed to develop them.

Internal Controls

Effective internal controls are necessary for the Company to provide reliable financial reports and to help prevent fraud. Although the Company undertakes a number of procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities laws, the Company cannot be certain that such measures will ensure that the Company will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm the Company's results of operations or cause it to fail to meet its reporting obligations. If the Company or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in the Company's consolidated financial statements and adversely affect the trading price of the Common Shares.

Litigation Risks

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

AUDIT COMMITTEE INFORMATION

The Audit Committee has been structured to comply with the requirements of National Instrument 52-110. The Board has determined that the Audit Committee members have the appropriate level of financial understanding and industry-specific knowledge to be able to perform their duties. A copy of the Audit Committee mandate and the additional disclosure required under National Instrument 52-110 is attached to this Annual Information Form as Schedule "D".

ADDITIONAL INFORMATION

Additional information relating to the Company can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans is contained in the Company's information circular for the Company's most recent annual meeting of securityholders that involved the election of directors. Additional financial information is contained in the Company's financial statements and the related management's discussion and analysis for the Company's most recently completed financial year.

SELECTED ABBREVIATIONS

In this Annual Information Form, unless otherwise indicated or the context otherwise requires, the following abbreviations shall have the meaning set forth below:

Crude Oil and Natural Gas Liquids

Bbls/d	barrels of oil per day
Bbls or Bbl	barrels of oil
Boe	barrel of oil equivalent
Boe/d	barrel of oil equivalent per day
$/Bbl	Canadian dollars per barrel of oil
$/Boe	Canadian dollars per barrel of oil equivalent
Mbbls	thousand barrels
MBoe	thousand barrels of oil equivalent
Mbbls/d	thousand barrels of oil per day
MMbbls	million barrels of oil
MMboe	million barrels of oil equivalent
MMboe/d	million barrels of oil equivalent per day
NGL	natural gas liquids

Natural Gas

Bcf	billion cubic feet
cf	cubic feet
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
Mcfe	thousand cubic feet of gas equivalent
Mcfe/d	thousand cubic feet of gas equivalent per day
MMbtu	million British thermal units

MMcf	million cubic feet
MMcf/d	million cubic feet per day
MMcfe	million cubic feet of gas equivalent
MMcfe/d	million cubic feet of gas equivalent per day
$/Mcf	Canadian dollars per thousand cubic feet
$/MMbtu	Canadian dollars per million British thermal units
GJ	gigajoule
GJs/d	gigajoules per day
$/GJ	Canadian dollar per gigajoule

Other

km	kilometres
km2	square kilometres
$, Cdn, Cdn or $dollars	Canadian dollars
$000s or M$	thousand dollars
MM$	million dollars
$US or US$	United States dollars
2D	two dimensional
3D	three dimensional

SELECTED CONVERSIONS

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.320
cubic metres	cubic feet	35.315
Bbls	cubic metres	0.159
cubic metres	Bbls	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Information Form constitute forward-looking statements. These statements relate to future events or the Company's future performance. All statements other than statements of historical fact are forward-looking statements. The use of any of the words "anticipate", "plan", "contemplate", "continue", "estimate", "expect", "intend", "propose", "might", "may", "will", "shall", "project", "should", "could", "would", "believe", "predict", "forecast", "pursue", "potential" and "capable" and similar expressions are intended to identify forward-looking statements. 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. No assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form. In addition, this Annual Information Form may contain forward-looking statements and forward-looking information attributed to third-party industry sources.

In particular, this Annual Information Form contains, without limitation, forward-looking statements pertaining to the following:

- the reserve potential of the Company's assets;

- the production from the Company's assets;
- the Company's growth strategy and opportunities;
- the Company's capital exploration and development programs and future capital requirements;
- the estimated quantity and value of the Company's proved and probable reserves;
- the Company's estimates of future interest and foreign exchange rates;
- the Company's environmental considerations;
- the Company's expectations regarding commodity prices;
- the timing of commencement of certain of the Company's operations and the level of production anticipated by the Company;
- the potential for production disruption and constraints;
- supply and demand fundamentals for crude oil and natural gas;
- the Company's access to adequate pipeline capacity;
- the Company's access to third-party infrastructure;
- the Company's drilling and recompletion plans;
- industry conditions pertaining to the oil and gas industry;
- the Company's plans for, and results of, exploration and development activities;
- the planned construction of the Company's gathering, transportation and processing facilities and related infrastructure;
- the timing for receipt of regulatory approvals;
- the Company's treatment under governmental regulatory regimes and tax laws;
- the Company's expectations regarding having adequate human resource staffing; and
- the Company's dividend policy.

With respect to forward-looking statements and forward-looking information contained in this Annual Information Form, assumptions have been made regarding, among other things:

- future crude oil and natural gas prices;
- the Company's ability to obtain qualified staff and equipment in a timely and cost-efficient manner;
- the regulatory framework governing royalties, taxes and environmental matters in the jurisdictions in which the Company conducts its business and any other jurisdictions in which the Company may conduct its business in the future;
- the Company's ability to market production of oil and natural gas successfully to customers;
- the Company's future production levels;
- the applicability of technologies for recovery and production of the Company's reserves;
- the recoverability of the Company's reserves;
- future capital expenditures to be made by the Company;
- future cash flows from production;
- future sources of funding for the Company's capital program;
- the Company's future debt levels;
- geological and engineering estimates in respect of the Company's reserves;
- the geography of the areas in which the Company is conducting exploration and development activities;
- the impact of competition on the Company; and
- the Company's ability to obtain financing on acceptable terms.

Actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and included elsewhere in this Annual Information Form, including:

- operating and capital costs;
- the Company's status and stage of development;
- general economic, market and business conditions;
- volatility in market prices for crude oil and natural gas and hedging activities related thereto;
- risks related to the exploration, development and production of oil and natural reserves;
- risks related to the timing of completion of the Company's projects;

- competition for, among other things, capital, the acquisition of reserves and resources and skilled personnel;
- operational hazards;
- actions by governmental authorities, including changes in government regulation and taxation;
- environmental risks and hazards;
- risks inherent in the exploration, development and production of oil and natural gas which may create liabilities to the Company in excess of the Company's insurance coverage;
- failure to accurately estimate abandonment and reclamation costs;
- failure of third parties' reviews, reports and projections to be accurate;
- the availability of capital on acceptable terms;
- political risks;
- changes to royalty or tax regimes;
- the failure of the Company or the holders of certain licenses or leases to meet specific requirements of such licenses or leases;
- claims made in respect of the Company's properties or assets;
- aboriginal claims;
- unforeseen title defects;
- risks arising from future acquisition activities;
- hedging strategies;
- potential conflicts of interest;
- the potential for management estimates and assumptions to be inaccurate;
- restrictions contained in the Company's;
- additional indebtedness;
- volatility in the market price of the Common Shares of the Company;
- the absence of an existing public market for the Common Shares;
- the effect that the issuance of additional securities by the Company could have on the market price of the Common Shares;
- failure to engage or retain key personnel;
- potential losses which would stem from any disruptions in production, including work stoppages or other labour difficulties, or disruptions in the transportation network on which the Company is reliant;
- uncertainties inherent in estimating quantities of oil and natural gas reserves;
- failure to acquire or develop replacement reserves;
- geological, technical, drilling and processing problems, including the availability of equipment and access to properties;
- failure by counterparties to make payments or perform their operational or other obligations to the Company in compliance with the terms of contractual arrangements between the Company and such counterparties;
- current global financial conditions, including fluctuations in interest rates, foreign exchange rates and stock market volatility; and
- the other factors discussed under "Risk Factors" in this Annual Information Form.

Forward looking statements and other information contained herein concerning the oil and gas industry and the Company's general expectations concerning this industry are based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. The industry involves risks and uncertainties and is subject to change based on various factors.

In addition, information and statements in this Annual Information Form relating to "reserves" are deemed to be forward-looking information and statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and that the reserves described can be profitably produced in the future. See also "Certain Reserves Data Information" below. Readers are cautioned that the foregoing list of risk factors should not be construed as exhaustive.

Additional information on these and other factors that could affect Tourmaline's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com).

The forward-looking statements included in this Annual Information Form are expressly qualified by this cautionary statement and are made as of the date of this Annual Information Form. The Company does not undertake any obligation to publicly update or revise any forward-looking statements except as expressly required by applicable securities laws.

CERTAIN RESERVES DATA INFORMATION

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

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

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

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

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

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

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

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed nonproducing. 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.

In this Annual Information Form:

(a) the discounted and undiscounted net present value of future net revenues attributable to reserves do not represent the fair market value of reserves;

(b) there is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, NGL and natural gas reserves provided in this Annual Information Form are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and NGL reserves may be greater than or less than the estimates provided in this Annual Information Form;

(c) the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation; and

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

SCHEDULE "A"
–
GLJ PETROLEUM CONSULTANTS LTD.
FORM 51-101F2
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Tourmaline Oil Corp. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (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, 2010, and identifies the respective portions thereof that we have audited, evaluated and reviewed 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	February 25, 2011	Canada	-	906,264	-	906,264

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

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

EXECUTED as to our report referred to above.

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, March 24, 2011.

ORIGINALLY SIGNED BY

Jodi L. Anhorn M. Sc., P. Eng.
Vice-President

SCHEDULE "B"
–
AJM PETROLEUM CONSULTANTS
FORM 51-101F2
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the Board of Directors of Tourmaline Oil Corp. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2010, 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)			
			Audited	**Evaluated**	**Reviewed**	**Total**
			M$	**M$**	**M$**	**M$**
AJM Petroleum Consultants	Tourmaline Oil Corp. Reserve Estimates and Economic Evaluation February 25, 2011	Canada	-	$288,486.30	-	$288,486.30

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

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

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

Executed as to our report referred to above.

AJM Petroleum Consultants
Fifth Avenue Place, East Tower
6th Floor, 425 – 1st Street S.W.
Calgary, Alberta T2P 3P8

Original signed by: "Lynn Kis"
Lynn Kis, P. Eng.
Vice President Engineering
Execution date: February 25, 2011

SCHEDULE "C"

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

Management of Tourmaline Oil 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, 2010, estimated using forecast prices and costs.

GLJ Petroleum Consultants Ltd. and AJM Petroleum Consultants, each an independent qualified reserves evaluator, has evaluated the Company's reserves data. The reports of the independent qualified reserves evaluator are presented below.

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

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

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

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

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

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

(e) the filing of Form 51-102F2 which is the reports of the independent qualified reserves evaluators on the reserves data; and

(f) the content and filing of this report.

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

DATED as of this 25th day of March, 2011.

(signed)	*"Michael L. Rose"* Michael L. Rose President, Chief Executive Officer and Director	(signed)	*"Brian G. Robinson"* Brian G. Robinson Vice President, Finance and Chief Financial Officer
(signed)	*"Robert W. Blakely"* Robert W. Blakely Director	(signed)	*"Phillip A. Lamoreaux"* Phillip A. Lamoreaux Director

SCHEDULE "D"

AUDIT COMMITTEE MANDATE AND AUDIT COMMITTEE DISCLOSURE

AUDIT COMMITTEE MANDATE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Tourmaline Oil Corp. ("**Tourmaline**" or the "**Company**") to which the Board has delegated its responsibility for the oversight of the following:

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

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

The primary objectives of the Committee are as follows:

5. To assist directors of Tourmaline ("**Directors**") in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Company and related matters;
6. To provide better communication between Directors and external auditors;
7. To enhance the external auditor's independence;
8. To increase the credibility and objectivity of financial reports; and
9. To strengthen the role of the outside Directors by facilitating in depth discussions between Directors on the Committee, management of Tourmaline ("**Management**") and external auditors.

Membership of Committee

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

Mandate and Responsibilities of Committee

It is the responsibility of the Committee to:

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

2. Satisfy itself on behalf of the Board with respect to Tourmaline's internal control systems identifying, monitoring and mitigating business risks; and ensuring compliance with legal, ethical and regulatory requirements.

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

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

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

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

   - recommend to the Board the external auditors to be nominated;
   - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;
   - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Company to determine the auditors' independence;
   - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
   - review and pre-approve any non-audit services to be provided to Tourmaline or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member(s) report to the Committee at the next scheduled meeting such pre-approval and the member(s) comply with such other procedures as may be established by the Committee from time to time

6. Review with external auditors (and internal auditor if one is appointed by Tourmaline) their assessment of the internal controls of Tourmaline, their written reports containing recommendations for improvement, and Management's response and follow-up to any identified weaknesses. The Committee will also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Tourmaline and its subsidiaries.

7. Review risk management policies and procedures of the Company (i.e., hedging, litigation and insurance).

8. Establish a procedure for:

   - the receipt, retention and treatment of complaints received by Tourmaline regarding accounting, internal accounting controls or auditing matters; and
   - the confidential, anonymous submission by employees of Tourmaline of concerns regarding questionable accounting or auditing matters.

9. Review and approve Tourmaline's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of the Company.

The Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Company. The Committee will also have the authority to investigate any financial activity of Tourmaline. All employees of Tourmaline are to cooperate as requested by the Committee.

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

Meetings and Administrative Matters

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

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

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

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

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

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

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

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

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

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

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

AUDIT COMMITTEE DISCLOSURE

Audit Committee Mandate and Terms of Reference

The Board has adopted a written mandate and terms of reference for the Audit Committee, which sets out the Audit Committee's responsibility for (among other things) reviewing the Company's financial statements and the Company's public disclosure documents containing financial information and reporting on such review to the Board, ensuring the Company's compliance with legal and regulatory requirements, overseeing qualifications, engagement, compensation, performance and independence of the Company's external auditors, and reviewing, evaluating and approving the internal control and risk management systems that are implemented and maintained by management. A copy of the Audit Committee mandate and terms of reference is set forth above.

Composition of the Audit Committee and Relevant Education and Experience

The Audit Committee consists of Messrs. Blakely (Chair), Lamoreaux and MacDonald. Each of the members of the Audit Committee is considered "financially literate" and each is considered "independent" within the meaning of NI 52-110.

The Company believes that each of the members of the Audit Committee possesses: (a) an understanding of the accounting principles used by the Company to prepare its financial statements; (b) the ability to assess the general application of such accounting principles in connection with the accounting for estimates, accruals and reserves; (c) experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Company's financial statements, or experience actively supervising one or more individuals engaged in such activities; and (d) an understanding of internal controls and procedures for financial reporting. For a summary of the education and experience of each member of the Audit Committee that is relevant to the performance of his responsibilities as a member of the Audit Committee, see "Directors and Officers" in the Annual Information Form.

Pre–Approval Policies and Procedures for the Engagement of Non–Audit Services

The Audit Committee is expected to adopt specific policies and procedures for the engagement of non–audit services, as described in the mandate of the Audit Committee.

External Audit Service Fees

The following table summarizes the fees paid by the Company and its subsidiaries to its auditors, KPMG LLP, for external audit and other services during the periods indicated.

Year	Audit Fees(1)	Audit – Related Fees(2)	Tax Fees(3)	All Other Fees(4)
	($)	($)	($)	($)
2010....................	300,000	104,000	9,450	745,000
2009	327,500	185,000	8,000	-

Notes:

(1) Represents the aggregate fees billed by the Company's external auditor in each of the last two fiscal years for audit services.

(2) Represents the aggregate fees billed in each of the last two fiscal years by the Company's external auditor for assurance and related services that are reasonably related to the performance of the audit or review of the Company's financial statements (and not reported under the heading "Audit Fees"). The services comprising the fees disclosed under this category consisted of the conduct of due diligence procedures in connection with financings and acquisitions undertaken by the Company.

(3) Represents the aggregate fees billed in each of the last two fiscal years by the Company's external auditor for professional services for tax compliance, tax advice and tax planning. The services comprising the fees disclosed under this category consisted of tax consultations and tax compliance services.

(4) Represents the aggregate fees billed in each of the last two fiscal years by the Company's external auditor for products and services not included under the headings "Audit Fees", "Audit Related Fees" and ""Tax Fees".