ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2019

March 3, 2020

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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**"), in the Canadian Oil and Gas Evaluation Handbook maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter) (the "**COGE Handbook**"), in the Canadian Securities Administrators Staff Notice 51-324 – *Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities* and under the heading "*Selected Abbreviations*" herein. 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, 2019. All dollar amounts herein are in Canadian dollars, unless otherwise stated. See "*Selected Abbreviations*", "*Selected Conversions*", "*Forward-Looking Statements*" and "*Certain Reserves Data Information*". Certain portions of Tourmaline's audited consolidated financial statements ("**Financial Statements**") and Management's Discussion and Analysis ("**MD&A**") for the year ended December 31, 2019 are incorporated by reference into this Annual Information Form as indicated herein. The Financial Statements and MD&A are available on SEDAR at www.sedar.com.

CORPORATE STRUCTURE

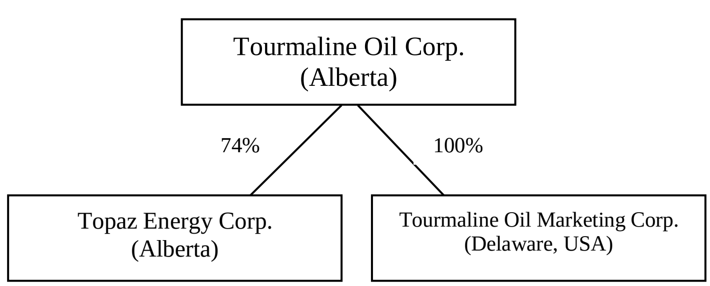
Name, address and incorporation

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, amalgamated with its wholly-owned subsidiary Altia Energy Ltd. ("**Altia**") on January 1, 2011, amalgamated with its wholly-owned subsidiary Cinch Energy Corp. ("**Cinch**") on January 1, 2012, amalgamated with its wholly-owned subsidiary Huron Energy Corporation ("**Huron**") on January 1, 2013, amalgamated with its wholly-owned subsidiary Santonia Energy Inc. ("**Santonia**") on January 1, 2015, amalgamated with its wholly-owned subsidiaries Bergen Resources Inc. ("**Bergen**") and Mapan Energy Ltd. ("**Mapan**") on January 1, 2016, 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 2400, 525 – 8th Avenue S.W., Calgary, Alberta T2P 1G1.

Intercorporate relationships

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



DESCRIPTION OF THE BUSINESS

Overview

Tourmaline is a Canadian senior crude oil and natural gas exploration and production company focused on providing strong and predictable long-term growth and a steady return to shareholders 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 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, joint ventures and land acquisitions combined with its active capital exploration and development program, Tourmaline has increased current production to approximately 310,500 Boe/d. The Company has assembled an extensive undeveloped land position with a large, multi-year drilling inventory and operating control of important natural gas processing and transportation infrastructure in three core long-term growth areas – the Alberta Deep Basin, NEBC Montney and the Peace River High Triassic Oil Complex.

To date, the Company has raised approximately $4.0 billion through private placement equity financings and public offerings, approximately $375.2 million of which was raised from Tourmaline's directors, officers, employees and their associates, and strategically completed a number of acquisitions to cost-effectively build its current production and extensive land position. The acquisitions have complemented 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 three 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 commodity price environment.

Business Strategy

Tourmaline's long-term business strategy is to increase shareholder value by providing both strong and predictable long-term growth and a steady return to shareholders through an aggressive exploration, development, production and acquisition program in the WCSB by building its extensive asset base in its 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; pursuing strategic acquisitions with significant potential synergies; undertaking wildcat exploration drilling for new pool discoveries and enhancing returns by focusing on operational and cost efficiencies. The Company strives to be one of the lowest cost producers in the WCSB in order to accomplish its business strategy in any economic and commodity price environment.

General Development of the Business

2017

On November 8, 2017, Tourmaline announced its transition to a dividend paying company.

On December 5, 2017, Tourmaline completed a private placement of 1,300,000 "flow-through" Common Shares at a price of $31.20 per Common Share for aggregate gross proceeds of approximately $40.6 million.

2018

On March 6, 2018, the Board of Directors of the Company (the "**Board**") declared its first quarterly dividend of $0.08 per Common Share payable on March 29, 2018 to shareholders of record on March 14, 2018.

On May 8, 2018, the Board increased the Company's quarterly dividend by 12.5% to $0.09 per Common Share, which was paid on June 29, 2018.

On May 15, 2018, Tourmaline completed a private placement of 1,000,000 "flow-through" Common Shares at a price of $30.00 per Common Share for aggregate gross proceeds of approximately $30.0 million.

On August 1, 2018, the Board increased the Company's quarterly dividend by an additional 11% to $0.10 per Common Share, which was paid on September 28, 2018.

2019

On May 8, 2019, the Board increased the Company's quarterly dividend by 20% to $0.12 per Common Share, which was paid on June 28, 2019.

On July 4, 2019, the Toronto Stock Exchange accepted Tourmaline's notice of intention to commence a normal course issuer bid ("**NCIB**"**).** The NCIB allows Tourmaline to purchase up to 13,602,507 Common Shares (subject to a daily limit of 188,533 Common Shares) over a twelve month period commencing on July 8, 2019 and expiring no later than July 7, 2020. As at December 31, 2019, Tourmaline had purchased 1,053,000 Common Shares under the NCIB.

On October 31, 2019, Tourmaline purchased the 9.4% minority interest in Exshaw Oil Corp, ("**Exshaw**"), resulting in Exshaw becoming a wholly-owned subsidiary of Tourmaline. Subsequently, in early November 2019, Tourmaline purchased the entirety of Exshaw's oil and gas assets and Exshaw's name was changed to "Topaz Energy Corp." ("**Topaz**").

On November 14, 2019, Tourmaline and Topaz completed a transaction which resulted in the formation of a unique, private, hybrid royalty and infrastructure company whereby Topaz purchased from Tourmaline certain revenue-generating oil and gas assets (the "**New Assets**"), which provide Topaz with the following three separate revenue streams ("**Revenue Streams**"):

(1) A gross overriding royalty on natural gas, oil and condensate production on 100% of Tourmaline's then-existing lands (approximately 2.2 million net acres);

(2) A non-operated 45% working interest in two natural gas processing plants underpinned by long-term take-or-pay commitments from Tourmaline; and

(3) A contracted interest in a portion of certain third-party revenues generated by natural gas processing and handling agreements.

Consideration paid to Tourmaline by Topaz consisted of $194.5 million in cash and 59.1 million Topaz common shares. The cash portion of the purchase consideration was funded by a private placement to investors of 20.9 million Topaz common shares at a price of $10.00 per share. After giving effect to the completion of the transaction, Topaz is 74% owned by Tourmaline and 26% owned by the investors.

Tourmaline's Reserves and Net Present Values of Future Net Revenue included in the Statement of Reserves Data and Other Oil and Gas Information contained herein include the full impact of the sale of the New Assets to Topaz notwithstanding Tourmaline's 74% ownership interest in Topaz. The Net Present Values of Future Net Revenue on a Total Proved Plus Probable basis (discounted at a rate of 10%) would increase by approximately 7% had the Topaz transaction not occurred. On a Proved Producing and Total Proved basis, the Net Present Values of Future Net Revenue (discounted at a rate of 10%) would increase by approximately 9% and 8%, respectively.

Potential Acquisitions and Financings

Tourmaline continues to evaluate potential acquisitions of all types of petroleum and natural gas and other energy-related assets and/or companies as part of its ongoing acquisition program. Tourmaline is regularly in the process of evaluating several potential acquisitions at any one time, which individually or together could be material. Tourmaline cannot predict whether any current or future opportunities will result in one or more acquisitions for Tourmaline. In addition, Tourmaline may, in the future, complete financings of equity or debt (which may be convertible into equity) for purposes that may include financing of acquisitions, Tourmaline's operations and capital expenditures and repayment of indebtedness.

Acquisition Summary

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

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
July 12, 2011	Cinch acquisition[5]	Dawson/Musreau-Kakwa	$211.1	3,700	134,274	87,580
November 30, 2012	Huron acquisition[6]	Groundbirch/Sunrise/Tupper	$245.4	5,500	84,405	55,766
April 24, 2014	Santonia acquisition[7]	Wilrich/Notikewin/Viking/Falher/ Cardium	$177.4	3,800	158,671	92,364
April 1, 2015	Perpetual acquisition	West Edson	$258.7	5,750	37,760	18,581
July 20, 2015	Bergen acquisition[8]	Mulligan	$24.6	500	57,760	27,253
August 14, 2015	Mapan acquisition[9]	Chinook Ridge/Berland/Cecilia/Bigstone	$89.6	5,500	216,916	166,898
January 29, 2016	Alberta Deep Basin acquisition	Minehead/Edson/Ansell	$183.0	4,750	80,320	55,129
November 30, 2016	Shell Canada Acquisition	Alberta Deep Basin/Gundy NEBC	$1,367.8	24,850	256,035	185,789
August 13, 2019	Peace River Re-acquisition	Peace River High	$175.0	5,600	-	82,544
October 31, 2019	NEBC Acquisition	Gundy NEBC	$49.0	-	11,413	8,559
			$3,635.6	**73,860**	**1,730,313**	**1,239,721**

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.
(5) Subsequent to the Cinch acquisition, Tourmaline amalgamated with Cinch on January 1, 2012 under the ABCA, continuing as Tourmaline Oil Corp.
(6) Subsequent to the Huron acquisition, Tourmaline amalgamated with Huron on January 1, 2013 under the ABCA, continuing as Tourmaline Oil Corp.
(7) Subsequent to the Santonia acquisition, Tourmaline amalgamated with Santonia on January 1, 2015 under the ABCA, continuing as Tourmaline Oil Corp.
(8) Subsequent to the Bergen acquisition, Tourmaline amalgamated with Bergen on January 1, 2016 under the ABCA, continuing as Tourmaline Oil Corp.
(9) Subsequent to the Mapan acquisition, Tourmaline amalgamated with Mapan on January 1, 2016 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**		**Insider, Employee and Associate Participation**[29]	
	Shares Issued	**Total Gross Proceeds**	**Gross Subscriptions**	**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%
May 17, 2011	6,825,000[9]	$174,037,500	$12,750,000	7.3%
October 12, 2011	4,900,000[10]	$161,700,000	$9,900,000	6.1%
December 1, 2011	1,361,500[11]	$55,821,500	$6,621,500	11.9%
April 4, 2012	1,402,000[12]	$40,377,600	$4,377,600	10.8%
August 30, 2012	4,639,000[13]	$134,531,000	$1,131,000	0.8%
November 1, 2012	1,050,000[14]	$38,745,000	$1,845,000	4.8%
March 12, 2013	6,615,000[15]	$233,160,250	$4,610,250	2.0%
October 8, 2013	4,420,000[16]	$193,646,250	$5,748,750	3.0%
February 12, 2014	4,615,198[17]	$219,221,905	$721,905	0.3%
June 2, 2014	1,150,000[18]	$78,372,500	$8,314,300	10.6%
November 28, 2014	280,053[19]	$15,963,021	Nil	Nil
March 12, 2015	640,000[20]	$32,000,000	Nil	Nil
June 23, 2015	4,947,500[21]	$195,426,250	$2,133,000	1.1%
November 25, 2015	482,700[22]	$16,460,070	Nil	Nil
April 5, 2016	10,387,500[23]	$281,605,125	$1,016,625	0.4%
May 17, 2016	1,320,000[24]	$46,860,000	Nil	Nil
October 20, 2016	890,500[25]	$39,627,250	Nil	Nil
November 10, 2016	21,758,700[26]	$756,114,825	$6,081,250	0.8%
December 5, 2017	1,300,000[27]	$40,560,000	Nil	Nil
May 15, 2018	1,000,000[28]	$30,000,000	Nil	Nil
	187,558,275	**$4,014,604,406**	**$375,225,540**	**9.3%**

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) Public offering of 6,825,000 Common Shares at $25.50 per share which includes the issuance of 825,000 Common Shares issued pursuant to the exercise of the underwriters' over-allotment option and 500,000 Common Shares issued pursuant to a concurrent private placement to certain executive officers.
(10) Public offering of 4,900,000 Common Shares at $33.00 per share which includes the issuance of 600,000 Common Shares issued pursuant to the exercise of the underwriters' over-allotment option (completed on October 19, 2011) and 300,000 Common Shares issued pursuant to a concurrent private placement to certain executive officers.
(11) Public offering of 1,361,500 flow-through Common Shares at $41.00 per share which includes 161,500 Common Shares issued pursuant to a concurrent private placement to certain executive officers.

(12) Public offering of 1,250,000 flow-through Common Shares at $28.80 per share and a concurrent private placement of 152,000 flow-through Common Shares of which 94,000 flow-through Common Shares were issued to certain executive officers.
(13) Public offering of 4,600,000 Common Shares at $29.00 per share which includes the issuance of 600,000 Common Shares issued pursuant to the exercise of the underwriters' over-allotment option and a concurrent private placement of 39,000 Common Shares of which 37,000 Common Shares were issued to certain executive officers.
(14) Public offering of 1,000,000 flow-through Common Shares at $36.90 per share and a concurrent private placement of 50,000 flow-through Common Shares of which 16,000 flow-through Common Shares were issued to certain executive officers.
(15) Public offering of 5,750,000 Common Shares at $34.25 per share which includes the issuance of 750,000 Common Shares issued pursuant to the exercise of the underwriters' over-allotment option and 750,000 flow-through Common Shares at $42.15 per share. Concurrent with the public offering was a private placement of 30,000 Common Shares and 85,000 flow-through Common Shares of which 30,000 Common Shares and 17,000 flow-through Common Shares were issued to certain executive officers.
(16) Public offering of 3,450,000 Common Shares at $41.75 per share which includes the issuance of 450,000 Common Shares issued pursuant to the exercise of the underwriters' over-allotment option and 850,000 flow-through Common Shares at $51.60 per share. Concurrent with the public offering was a private placement of 45,000 Common Shares and 75,000 flow-through Common Shares of which 40,000 Common Shares and 27,100 flow-through Common Shares were issued to certain executive officers.
(17) Public offering of 4,600,000 Common Shares at $47.50 per share which includes the issuance of 600,000 Common Shares issued pursuant to the exercise of the underwriters' over-allotment option. Concurrent with the public offering was a private placement of 15,198 Common Shares of which 10,000 were issued to certain executive officers.
(18) Private placement of 1,150,000 flow-through Common Shares at $68.15 per share.
(19) Private placement of 280,053 flow-through Common Shares at $57.00 per share.
(20) Private placement of 640,000 flow-through Common Shares at $50.00 per share.
(21) Public offering of 4,887,500 Common Shares at $39.50 per share which includes the issuance of 637,500 Common Shares issued pursuant to the exercise of the underwriters' over-allotment option. Concurrent with the public offering was a private placement of 60,000 Common Shares of which 54,000 Common Shares were issued to certain executive officers.
(22) Private placement of 482,700 flow-through Common Shares at $34.10 per share.
(23) Public offering of 10,350,000 Common Shares at $27.11 per share. Concurrent with the public offering was a private placement of 37,500 Common Shares of which 33,000 were issued to certain executive officers.
(24) Private placement of 1,320,000 "flow-through" Common Shares at $35.50 per share.
(25) Private placement of 890,500 "flow-through" Common Shares at $44.50 per share.
(26) Public offering of 3,309,700 subscription receipts at $34.75 per receipt. Concurrent with the public offering was a private placement of 18,449,000 subscription receipts at $34.75 per receipt, including a non-brokered offering of 175,000 subscription receipts at $34.75 per receipt, of which 88,000 subscription receipts were issued to certain executive officers. All subscription receipts were subsequently converted to Common Shares on November 30, 2016 on a one-to-one basis.
(27) Private placement of 1,300,000 flow-through Common Shares at $31.20 per share.
(28) Private placement of 1,000,000 flow-through Common Shares at $30.00 per share.
(29) 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 three core long-term growth areas – an area within the WCSB approximately 250 km west of Edmonton, Alberta (the "**Alberta Deep Basin**") and areas within the WCSB extending from Grande Prairie, Alberta to approximately 100 km northwest of Fort St. John, NEBC ("**NEBC Montney**" and "**Peace River High Triassic Oil Complex**").

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 liquids-rich natural-gas-charged 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 with no mobile formation water. The primary vehicle for accessing the extensive reserves in these stacked sandstones is multi-stage fracture stimulation in both horizontal and vertical well-bores. Tourmaline utilizes 3D seismic data to select the majority of its drilling locations, and management believes it is an industry leader in adopting and continually adapting the improving drilling and completion technologies. These two factors allow the

Company to consistently deliver a significant portion of the highest productivity gas wells in the province on an annual basis. The majority of the Company's working interest lands have already received approval for down-spacing at four wells per section per zone or formation or resevoir.

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, Viking, Wilrich, Fahler and Notikewin Formations). Accordingly, each section in the Alberta Deep Basin core area is expected to include on average two to three targeted multi-stage stimulated horizontal wells in the Company's long-term development plan. Management estimates that up to 6,491 gross horizontal drilling locations exist on its Alberta Deep Basin holdings which are currently being assessed as part of the ongoing drilling program. These horizontal drilling locations have been included in the Company's development drilling inventory. Future evaluation of these multiple resource plays is an important component of the 2020 capital exploration and development program, with approximately 95 gross horizontal wells currently planned. Tourmaline has been targeting the more condensate and NGL rich formations (Cardium, Viking and Fahler) with horizontal drilling over the past two years. In addition, the Company has 2,373 vertical development locations, including 450 gross outer foothills thrust belt vertical wells with geologic and economic parameters similar to those of the horizontal inventory.

Tourmaline currently has ownership interests in thirteen natural gas plants in the Alberta Deep Basin, eight of which (the Wild River 14-20, the Hinton 6-32, the Minehead 15-12, the Anderson 1-9, the Edson 4-17, the Ansell 1-34, the Oldman 10-24 and the Sundance 15-7) are 100% owned and operated by Tourmaline. In aggregate, Tourmaline has in excess of 1 Bcf/d of natural gas processing capability within this plant network. Tourmaline's goal is to be one of the lowest-cost, most efficient operators in the Alberta Deep Basin, and the Company plans to optimize and systematically continue to further reduce costs of operating the Alberta Deep Basin assets.

In the Alberta Deep Basin, Tourmaline, since inception, has drilled over 800 gross natural gas wells and intends to drill an additional approximately 95 gross wells in 2020. Tourmaline is the largest producer in the Alberta Deep Basin with production currently estimated at approximately 175,000 – 180,000 Boe/d. The Company's land holdings in the core area are approximately 2,500 gross sections. Year-end 2019 proved plus probable reserves were 1,016.5 MMboe in the Alberta Deep Basin, with approximately 765 gross (684.7 net) future drilling locations recognized in the Consolidated Reserve Report (as defined herein).

NEBC Montney

Tourmaline's second core exploration and production area on the west flank of the Peace River High in NEBC is focused on 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 pursued with vertical wells 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 fine grained sandstone reservoirs of the Montney in the NEBC play area. It is in the Groundbirch/Sunrise/Dawson area of the Peace River Arch where senior management of Tourmaline gained extensive experience with Duvernay Oil Corp. and where Tourmaline concentrated its initial Montney exploration and production program.

The Company has assembled its large Montney position primarily through multiple acquisitions completed between 2009 and 2019. Late in 2016, the Company completed the largest property acquisition in the Company's history which included a new property in NEBC, adding 6,200 Boe/d of initial production, over 100 sections of land and 1,600 new Montney drilling locations in the Gundy CK area, which is northwest of the Company's existing Sunrise/Dawson/Sundown complex. Both the original Sunrise/Dawson complex and Gundy CK contain liquid-rich sweet gas in the Montney, allowing for lower, long-term operating costs compared to the majority of Montney focussed competitors pursuing sour gas. In NEBC, Tourmaline has an inventory of approximately 3,763 gross horizontal Montney development drilling locations, making the Company one of the largest participants in this resource play. To date, Tourmaline has drilled over 450 Montney multi-stage fracture-stimulated horizontal natural gas wells in NEBC with an additional approximately 100 gross Montney horizontal wells planned for 2020. Tourmaline's 2020 – 2021 two year development plan for the Gundy CK Montney asset includes continuing to apply drilling and completion practices developed in the Groundbirch/Sunrise/Dawson area in order to continue reduce development costs, improve efficiencies and raise estimated ultimate recoveries (EUR). Tourmaline has amongst the lowest Montney drill and complete capital costs in industry.

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, the ultimate timing of which is dependent on a natural gas price recovery. Tourmaline owns and operates six significant natural gas processing facilities with aggregate capacity of 525 MMcf/d with related gas gathering systems and NGL handling infrastructure in the NEBC complex, including a new 200 MMcf/d facility built and commissioned at Gundy in 2019 in order to efficiently processes the liquids-rich natural gas produced as a result of ongoing development in the Gundy CK area including installation of an ethane rejection deep-cut gas processing facility. To further support the Company's development plans in the area, Tourmaline is also planning an additional 200 MMcf/d expansion of the Gundy facility for late 2021/early 2022. Current production in the NEBC Montney complex is approximately 515 MMcf/d of natural gas and a combined 25,000 bbls per day of associated natural gas liquids, condensate and crude oil. As at December 31, 2019, Tourmaline holds approximately 310 gross sections of Montney rights in the core area with 1,344.1 MMboe of proved plus probable reserves evaluated by the independent engineers at December 31, 2019 including approximately 946 gross (884.1 net) future drilling locations recognized in the Consolidated Reserve Report.

Peace River High Triassic Oil Complex

The third core area on the Alberta portion of the greater Peace River High is the Company's exploration and production complex at Spirit River-Mulligan-Earring, Alberta. The majority of the current production in the complex is derived from oil and natural gas-charged reservoirs of the Triassic Charlie Lake and Montney formations. This area, currently producing approximately 21,000 Boe/d net to Tourmaline, has a large inventory of vertical and horizontal development drilling prospects in the Charlie Lake and Montney formations as well as attractive plays in several other formations. The Company has drilled over 340 horizontal oil wells to date and plans an additional approximately 25 gross horizontals through 2020. As at December 31, 2019, the Company has a defined inventory of 1,192 future Charlie Lake horizontals (gross) and 634 Montney horizontal locations (gross).

Proved plus probable reserves in the area at December 31, 2019 are estimated to be 241.9 MMboe including approximately 524 gross (508.1 net) future drilling locations recognized in the Consolidated Reserve Report. The Company currently owns and operates two significant oil batteries capable of handling 48,000 bpd of fluids and the associated natural gas is delivered to a third party for processing. Tourmaline also has an owned and operated 60 MMcf/d sour gas processing facility at Spirit River.

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 February 25, 2020 and effective as at December 31, 2019.

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, 2019, with an execution date of February 25, 2020 (the "**GLJ Reserve Report**") and the report of Deloitte LLP ("**Deloitte**") dated effective December 31, 2019, with an execution date of February 25, 2020 (the "**Deloitte Reserve Report**"), which are contained in the consolidated report of GLJ dated effective December 31, 2019, with a preparation date of February 25, 2020 (the "**Consolidated Reserve Report**"). The Consolidated Reserve Report evaluates, as at December 31, 2019, the crude oil, NGL and natural gas reserves of Tourmaline and, notwithstanding that Tourmaline owns 74% of Topaz, includes the full impact of the New Assets.

GLJ evaluated in the GLJ Reserve Report approximately 82.7% of the assigned total proved plus probable reserves and 80.3% of the total proved plus probable future net revenue discounted at 10% recognized in the

Consolidated Reserve Report. Deloitte evaluated in the Deloitte Reserve Report approximately 17.3% of the assigned total proved plus probable reserves and 19.7% of the total proved plus probable future net revenue discounted at 10% recognized in the Consolidated Reserve Report. Deloitte evaluated in the Deloitte Reserve Report the Company's greater Hinton, Kakwa and Alberta Foothills properties located in the Alberta Deep Basin and the Company's Mulligan and Spirit River properties located in the Alberta portion of the Peace River High. Deloitte incorporated the forecast price and cost assumptions as described below under the heading "Consolidated Reserve Report Pricing 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 Deloitte Reserve Report adjusted to apply certain of GLJ's assumptions and methodologies used in the preparation of the GLJ Reserve Report to the Deloitte Reserve Report. 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 Deloitte Reserve Report. Also due to rounding, certain columns may not add. The price forecast used in the reserve evaluations is an equal weighted average of the January 1, 2020 price forecasts for GLJ, Sproule Associates Ltd. and McDaniel & Associates Consultants Ltd.

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 Deloitte were engaged to provide evaluations of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

Shale natural gas is required to be presented separately from conventional natural gas as its own product type pursuant to NI 51-101. While the Tourmaline Montney reserves do not strictly fit the definition of "shale gas" as defined in NI 51-101 because the natural gas is not "primarily adsorbed" as stated within the definition, the Montney reserves have been included as shale gas for purposes of this disclosure.

All of the Company's consolidated reserves are in Canada and, more specifically, substantially all are 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 B 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 and reclamation 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)

The following tables summarize the Company's gross reserves defined as the working interest share of reserves prior to the deduction of interest owned by others (burdens). Royalty interest reserves are not included in Company gross reserves. Company net reserves are defined as the working net carried, and royalty interest reserves after deduction of all applicable burdens.

Summary of Oil and Gas Reserves and
Net Present Values of Future Net Revenue
as of December 31, 2019
Forecast Prices and Costs(1)

	Light & Medium Crude Oil		Conventional Natural Gas		Shale Natural Gas		Natural Gas Liquids		Total Oil Equivalent	
Reserves Category	**Company Gross (Mbbls)**	**Company Net (Mbbls)**	**Company Gross (MMcf)**	**Company Net (MMcf)**	**Company Gross (MMcf)**	**Company Net (MMcf)**	**Company Gross (Mbbls)**	**Company Net (Mbbls)**	**Company Gross (Mboe)**	**Company Net (Mboe)**
Proved Producing	13,948	11,422	1,676,894	1,505,877	910,873	844,148	82,118	68,535	527,361	471,628
Proved Developed Non-Producing	1,935	1,504	95,010	85,260	208,272	196,007	12,432	10,958	64,914	59,340
Proved Undeveloped	32,189	26,203	1,929,133	1,751,774	1,408,310	1,308,908	113,735	102,419	702,164	638,736
Total Proved	48,072	39,130	3,701,036	3,342,911	2,527,455	2,349,063	208,285	181,912	1,294,439	1,169,704
Total Probable	48,912	39,478	2,412,245	2,173,075	3,653,824	3,279,086	247,566	210,547	1,307,490	1,158,719
Total Proved Plus Probable	96,984	78,608	6,113,281	5,515,987	6,181,279	5,628,148	455,851	392,458	2,601,928	2,328,422

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

	Before Income Taxes Discounted at (2) (%/year)					After Income Taxes Discounted at (2) (3) (%/year)					Unit Value Before Income Tax Discounted at 10%/year	
Reserves Category	**0**	**5**	**10**	**15**	**20**	**0**	**5**	**10**	**15**	**20**	**($/Boe)**	**($/Mcfe)**
Proved Producing	6,776,073	5,475,633	4,579,234	3,953,261	3,496,236	6,513,916	5,329,729	4,494,030	3,901,446	3,463,622	9.71	1.62
Proved Developed Non-Producing	951,690	723,446	581,989	487,603	420,666	703,333	555,992	464,566	402,764	357,903	9.81	1.63
Proved Undeveloped	8,114,346	5,258,108	3,623,511	2,611,296	1,943,173	5,988,919	3,824,651	2,584,398	1,819,464	1,317,883	5.67	0.95
Total Proved	15,842,109	11,457,187	8,784,733	7,052,160	5,860,075	13,206,167	9,710,371	7,542,994	6,123,674	5,139,408	7.51	1.25
Total Probable	20,521,808	10,555,460	6,308,597	4,165,195	2,945,016	15,169,537	7,746,820	4,579,558	2,987,161	2,086,554	5.44	0.91
Total Proved Plus Probable	36,363,916	22,012,647	15,093,330	11,217,355	8,805,091	28,375,704	17,457,191	12,122,552	9,110,834	7,225,961	6.48	1.08

Notes:

(1) Numbers may not add due to rounding.
(2) Values are presented on the basis that all Revenue Streams sold to Topaz are excluded from these tables notwithstanding the fact Tourmaline owns 74% of Topaz.
(3) The after-tax net present value of the Company's oil and gas properties reflects the tax burden on the properties on a stand-alone basis. It does not consider the Company's tax situation, or tax planning. It does not provide an estimate of the value at the Company level which may be significantly different. The Company's financial statements and management's discussion and analysis should be consulted for information at the Company level.

Total Future Net Revenue ($000s)
(Undiscounted)
as of December 31, 2019
Forecast Prices and Costs(1)(2)

Reserves Category	Revenue	Royalties	Operating Costs	Capital Development Costs	Abandonment and Reclamation Costs(3)	Future Net Revenue Before Income Tax	Income Tax	Future Net Revenue After Income Tax(4)
Proved Producing.........	12,077,042	1,248,887	3,611,456	50	440,576	6,776,073	262,157	6,513,916
Proved Developed Non-Producing	1,573,143	164,268	368,213	66,242	22,730	951,690	248,357	703,333
Proved Undeveloped……………..	17,308,773	1,640,354	3,550,448	3,805,349	198,275	8,114,346	2,125,427	5,988,919
Total Proved……………………...	30,958,957	3,053,509	7,530,117	3,871,642	661,581	15,842,109	2,635,941	13,206,167
Total Probable……………………	37,823,111	4,827,222	8,615,423	3,532,409	326,248	20,521,808	5,352,271	15,169,537
Total Proved Plus Probable………	68,782,068	7,880,731	16,145,540	7,404,051	987,829	36,363,916	7,988,212	28,375,704

Notes:

(1) Numbers may not add due to rounding.
(2) Values are presented on the basis that all Revenue Streams sold to Topaz are excluded from these tables notwithstanding the fact Tourmaline owns 74% of Topaz.
(3) Abandonment and Reclamation Costs includes all active and inactive assets, with or without associated reserves, inclusive of all wells (existing and undrilled), facilities and pipelines.
(4) The after-tax net present value of the Company's oil and gas properties reflects the tax burden on the properties on a stand-alone basis. It does not consider the Company's tax situation, or tax planning. It does not provide an estimate of the value at the Company level, which may be significantly different. The Company's financial statements and management's discussion and analysis should be consulted for information at the Company level.

Future Net Revenue
by Production Type
as of December 31, 2019
Forecast Prices and Costs

Reserves Category	Production Type(1)	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($000s) (2)	Unit Value (discounted at 10%/year) (2)	
			($/Boe)	($/Mcfe)
Proved Reserves	Light and Medium Crude Oil..	1,214,986	11.62	1.94
	Conventional Natural Gas...	3,247,914	5.84	0.97
	Shale Natural Gas	4,321,833	8.49	1.41
	Total..	**8,784,733**	**7.51**	**1.25**
Proved Plus Probable	Light and Medium Crude Oil..	1,965,330	9.38	1.56
	Conventional Natural Gas...	4,919,036	5.50	0.92
	Shale Natural Gas	8,208,964	6.71	1.12
	Total..	**15,093,330**	**6.48**	**1.08**

Note:

(1) By-products, including solution gas, natural gas liquids and other associated by-products are included in their main product group (natural gas or oil).
(2) Values are presented on the basis that all Revenue Streams sold to Topaz are excluded from these tables notwithstanding the fact Tourmaline owns 74% of Topaz.

Reconciliation of Changes in Reserves

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

Factors	Light and Medium Crude Oil Gross Proved (Mbbl)	Light and Medium Crude Oil Gross Probable (Mbbl)	Light and Medium Crude Oil Gross Proved Plus Probable (Mbbl)	Conventional Natural Gas Gross Proved (MMcf)	Conventional Natural Gas Gross Probable (MMcf)	Conventional Natural Gas Gross Proved Plus Probable (MMcf)
December 31, 2018	39,626	42,421	82,047	3,669,359	2,402,017	6,071,376
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery	5,081	4,972	10,053	320,573	80,700	401,273
Technical Revisions	(6,573)	(12,060)	(18,633)	60,802	(164,321)	(103,519)
Acquisitions	12,969	13,750	26,719	88,590	97,415	186,005
Dispositions	-	-	-	-	-	-
Economic Factors	(98)	(171)	(269)	(87,154)	(3,566)	(90,720)
Production	(2,932)	-	(2,932)	(351,135)	-	(351,135)
December 31, 2019	**48,072**	**48,912**	**96,984**	**3,701,036**	**2,412,245**	**6,113,281**

Factors	Shale Natural Gas Gross Proved (MMcf)	Shale Natural Gas Gross Probable (MMcf)	Shale Natural Gas Gross Proved Plus Probable (MMcf)	Total Natural Gas Liquids Gross Proved (Mbbl)	Total Natural Gas Liquids Gross Probable (Mbbl)	Total Natural Gas Liquids Gross Proved Plus Probable (Mbbl)
December 31, 2018	2,218,064	3,423,238	5,641,302	185,518	237,680	423,198
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery	374,021	110,239	484,260	32,220	6,845	39,065
Technical Revisions	92,533	103,835	196,368	7,425	(980)	6,445
Acquisitions	16,178	20,589	36,767	3,207	3,673	6,880
Dispositions	-	-	-	-	-	-
Economic Factors	(7,788)	(4,077)	(11,865)	(2,827)	348	(2,479)
Production	(165,553)	-	(165,553)	(17,258)	-	(17,258)
December 31, 2019	**2,527,455**	**3,653,824**	**6,181,279**	**208,285**	**247,566**	**455,851**

Factors	Total BOE Gross Proved (Mboe)	Total BOE Gross Probable (Mboe)	Total BOE Gross Proved Plus Probable (Mboe)
December 31, 2018	1,206,381	1,250,976	2,457,357
Discoveries	-	-	-
Extensions and Improved Recovery	153,066	43,641	196,707
Technical Revisions	26,408	(23,121)	3,286
Acquisitions	33,637	37,090	70,727
Dispositions	-	-	-
Economic Factors	(18,748)	(1,097)	(19,845)
Production	(106,305)	-	(106,305)
December 31, 2019	**1,294,439**	**1,307,489**	**2,601,928**

Notes to Reserves Data Tables:

(1) Numbers may not add due to rounding.
(2) Tourmaline has no bitumen, coalbed methane, gas hydrates, heavy crude oil, synthetic crude oil or synthetic gas reserves.
(3) Company gross reserves do not include royalty interests received by Tourmaline.

(4) The crude oil, natural gas liquids, conventional natural gas and shale natural gas reserve estimates presented in the GLJ Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

Reserve Categories

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

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

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

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

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

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

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

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

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

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

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

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

Levels of Certainty for Reported Reserves

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

(a) at least a 90 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 quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

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

(5) Well abandonment, disconnect and surface reclamation costs were estimated and included in the GLJ report for both wells that were assigned reserves and inactive wells that were not assigned reserves. Complete abandonment, disconnect and surface reclamation costs have also been estimated for gathering systems, batteries, plants and processing facilities.

Consolidated Reserve Report Pricing Assumptions

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

		Crude Oil and Natural Gas Liquids Pricing													
			NYMEX WTI Near Month Futures Contract Crude Oil at Cushing, Oklahoma									Alberta Natural Gas Liquids (Then Current Dollars)			
Year	Inflation[2] %	CAD/USD Exchange Rate $US/$Cdn[3]	Constant 2020 $ $US/Bbl	Then Current $US/ Bbl	Brent Blend Crude Oil FOB North Sea Then Current $US/Bbl	MSW, Light 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 Crude Oil Stream Quality at Hardisty Then Current $Cdn/Bbl	Heavy Crude Oil Proxy (12 API) at Hardisty Then Current $Cdn/Bbl	Light Sour 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	Spec Ethane $Cdn/Bbl	Edmonton Propane $Cdn/Bbl	Edmonton Butane $Cdn/Bbl	Edmonton C5+ Stream Quality $Cdn/Bbl
2020	0.0	0.7600	61.00	61.00	66.33	72.64	58.43	57.57	51.23	72.16	70.22	6.42	26.36	42.09	76.83
2021	1.7	0.7700	62.70	63.75	67.94	76.06	63.00	62.35	56.11	75.23	73.15	7.41	29.80	47.03	79.82
2022	2.0	0.7850	63.82	66.18	70.06	78.35	64.99	64.33	57.72	77.50	74.95	8.33	32.94	50.66	82.30
2023	2.0	0.7850	64.20	67.91	71.66	80.71	66.91	66.23	59.45	79.83	77.19	8.65	34.00	52.21	84.72
2024	2.0	0.7850	64.40	69.48	73.27	82.64	68.65	67.96	61.09	81.76	79.05	8.98	34.89	53.48	86.71
2025	2.0	0.7850	64.58	71.07	74.57	84.60	70.41	69.72	62.75	83.69	80.92	9.24	35.78	54.77	88.73
2026	2.0	0.7850	64.75	72.68	76.22	86.57	72.20	71.49	64.43	85.66	82.82	9.46	36.69	56.07	90.77
2027	2.0	0.7850	64.84	74.24	77.83	88.49	73.91	73.19	66.04	87.57	84.66	9.67	37.57	57.32	92.76
2028	2.0	0.7850	64.84	75.73	79.36	90.31	75.53	74.80	67.55	89.37	86.40	9.89	38.41	58.50	94.65
2029	2.0	0.7850	64.85	77.24	80.92	92.17	77.17	76.43	69.08	91.21	88.17	10.12	39.26	59.71	96.57
2030	2.0	0.7850	64.85	78.79	82.54	94.01	78.72	77.96	70.47	93.04	89.94	10.35	40.11	60.90	98.53
2031	2.0	0.7850	64.85	80.36	84.19	95.89	80.29	79.52	71.87	94.90	91.74	10.56	40.91	62.12	100.50
2032	2.0	0.7850	64.84	81.97	85.87	97.81	81.90	81.11	73.31	96.80	93.57	10.77	41.73	63.36	102.51
2033	2.0	0.7850	64.84	83.61	87.59	99.76	83.54	82.73	74.78	98.73	95.44	10.98	42.56	64.63	104.56
2034	2.0	0.7850	64.85	85.28	89.35	101.76	85.21	84.39	76.27	100.71	97.35	11.20	43.42	65.92	106.65
2035	2.0	0.7850	64.85	+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												
						Alberta Plant Gate			Saskatchewan Plant Gate			British Columbia	
	NYMEX Henry Hub Near Month Contract					Spot							
Year	Constant 2020 $ $US/ MMbtu	Then Current $US/MMbtu	Midwest Price @ Chicago Then Current $US/ MMbtu	AECO/NIT Spot Then Current $Cdn/ MMbtu	Dawn Price @ Ontario Then Current $US/MMbtu	Constant 2020 $ $Cdn/ MMbtu	Then Current $Cdn/ MMbtu	ARP $Cdn/ MMbtu	SaskEnergy $Cdn/ MMbtu	Spot $Cdn/ MMbtu	Sumas Spot $US/ MMbtu	Westcoast Station 2 $Cdn/ MMbtu	Spot Plant Gate $Cdn/ MMbtu
2020...............	2.62	2.62	2.53	2.04	2.58	1.82	1.82	1.83	1.93	2.49	2.16	1.66	1.41
2021...............	2.82	2.87	2.78	2.32	2.82	2.07	2.10	2.11	2.21	2.72	2.44	1.99	1.74
2022...............	2.95	3.06	2.96	2.62	3.01	2.30	2.39	2.40	2.50	2.89	2.72	2.31	2.07
2023...............	2.99	3.17	3.07	2.71	3.12	2.35	2.48	2.50	2.60	2.88	2.83	2.46	2.21
2024...............	3.01	3.24	3.15	2.81	3.20	2.39	2.58	2.59	2.70	2.98	2.90	2.56	2.31
2025...............	3.02	3.32	3.23	2.89	3.27	2.41	2.66	2.67	2.77	3.06	2.98	2.66	2.42
2026...............	3.02	3.39	3.30	2.96	3.34	2.42	2.72	2.74	2.84	3.13	3.05	2.73	2.48
2027...............	3.02	3.46	3.36	3.03	3.41	2.43	2.78	2.80	2.91	3.20	3.12	2.80	2.54
2028...............	3.02	3.52	3.43	3.10	3.48	2.44	2.85	2.87	2.98	3.27	3.18	2.87	2.61
2029...............	3.02	3.60	3.50	3.17	3.55	2.45	2.92	2.94	3.05	3.34	3.26	2.93	2.68
2030...............	3.02	3.67	3.58	3.24	3.62	2.46	2.99	3.00	3.12	3.41	3.33	3.00	2.74
2031...............	3.02	3.74	3.65	3.30	3.69	2.46	3.05	3.07	3.18	3.48	3.39	3.06	2.80
2032...............	3.02	3.81	3.72	3.37	3.77	2.46	3.11	3.13	3.24	3.55	3.46	3.12	2.85
2033...............	3.02	3.89	3.80	3.43	3.84	2.46	3.17	3.19	3.30	3.62	3.54	3.19	2.91
2034...............	3.02	3.97	3.87	3.50	3.92	2.46	3.23	3.25	3.37	3.70	3.61	3.25	2.97
2035...............	3.02	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.46	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Notes:

(1) Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by GLJ in the GLJ Reserve Report and Deloitte in the Deloitte Reserve Report, were an average of forecast prices and costs published by Sproule Associates Ltd. as at December 31, 2019 and GLJ and McDaniel & Associates Consultants Ltd. as at January 1, 2020 (each of which is available on their respective websites at www.sproule.com, www.gljpc.com, and www.mcdan.com). GLJ assigns a value to the Company's existing physical diversification contracts for natural gas for consuming markets at Dawn, Chicago, Ventura, Malin and PG&E based on forecasted differentials to NYMEX Henry Hub as per the aforementioned consultant average price forecast, contracted volumes and transportation costs. No incremental value is assigned to potential future contracts which were not in place as of December 31, 2019.
(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, 2019, the Company received the following weighted average prices, including realized gains and losses on financial instruments, in respect of its production: natural gas – $2.59/Mcf;

NGL – $15.33/bbl; and oil and condensate – $68.50/bbl. The overall weighted average price received by Tourmaline on an oil equivalent basis was $20.04/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 for years 2017 and 2018 as well as from January 1, 2019 to October 31, 2019). On October 31, 2019, Exshaw became a wholly-owned subsidiary of Tourmaline.

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, 2019, 2018 and 2017.

Proved Undeveloped Reserves

Year	Light Crude Oil and Medium Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)		Shale Natural Gas[(2)] (MMcf)		Natural Gas Liquids (Mbbl)		MBoe Oil Equivalent	
	First Attributed[(1)]	Cumulative at Year-end	First Attributed	Cumulative at Year-end	First Attributed	Cumulative at Year-end	First Attributed	Cumulative at Year-end	First Attributed	Cumulative at Year-end
2017	4,447	20,692	366,973	1,790,816	185,067	1,028,389	13,069	83,560	109,613	574,119
2018	4,056	25,008	266,730	1,927,661	178,286	1,310,007	16,658	106,988	94,884	671,607
2019	2,370	32,189	128,803	1,929,133	130,035	1,408,310	11,108	113,735	56,618	702,164

Notes:

(1) "First Attributed" refers to reserves first attributed on the effective date of the corresponding fiscal year.
(2) Because of product type guidelines and definitions, contained in NI 51-101, the Company's Montney proved reserves are classified as shale natural gas.

It is anticipated that most of the proved undeveloped locations will be drilled by December 31, 2023.

Probable Undeveloped Reserves

Year	Light Crude Oil and Medium Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)		Shale Natural Gas[(2)] (MMcf)		Natural Gas Liquids (Mbbl)		MBoe Oil Equivalent	
	First Attributed[(1)]	Cumulative at Year-end	First Attributed	Cumulative at Year-end	First Attributed	Cumulative at Year-end	First Attributed	Cumulative at Year-end	First Attributed	Cumulative at Year-end
2017	7,230	28,508	293,590	1,698,090	158,300	2,956,703	11,651	193,252	94,197	997,559
2018	4,699	35,637	268,608	1,793,200	84,574	3,085,264	14,790	209,952	78,353	1,058,666
2019	4,961	42,224	140,471	1,821,303	224,623	3,249,233	16,397	215,010	82,206	1,102,323

Notes:

(1) "First Attributed" refers to reserves first attributed on the effective date of the corresponding fiscal year.
(2) Because of product type guidelines and definitions, contained in NI 51-101, the Company's Montney probable reserves are classified as shale natural gas.

It is anticipated that most of the future development capital associated with the probable undeveloped reserves will be incurred by December 31, 2025.

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 three to seven 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 Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgements 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 the 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*".

GLJ's forecast of well abandonment and reclamation costs for all wells with reserves assigned are included in their report and therefore in their estimate of future net revenue. Abandonment and reclamation costs for wells for which no reserves are assigned and for Company-owned facilities are also included for the purposes of calculating GLJ's estimate of future net revenue. Refer to note 9 "*Decommissioning Obligations"* in the Financial Statements for further discussion on the Company's abandonment and reclamation obligations, which note is incorporated by reference herein.

The following table sets forth abandonment and reclamation costs deducted in the estimation of future net revenue in the Consolidated Reserve Report:

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

Year	**Abandonment and Reclamation Costs (Undiscounted)**	**Abandonment and Reclamation Costs (Discounted at 10%)**
2020	-	-
2021	-	-
2022	-	-
Thereafter	987,829	69,566
Total	**987,829**	**69,566**

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):

	Undiscounted Forecast Prices and Costs	
Year	**Proved Reserves**	**Proved Plus Probable Reserves**
2020	748,390	897,346
2021	935,193	1,227,853
2022	1,018,961	1,286,136
2023	754,098	1,092,795
2024	315,297	1,098,248
Thereafter	99,703	1,801,673
Total	**3,871,642**	**7,404,051**

Tourmaline expects that the capital listed in the preceding table will be funded through its existing cash balance, unutilized credit facilities, 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 from January 1, 2019 to October 31, 2019). On October 31, 2019, Exshaw became a wholly-owned subsidiary of Tourmaline.

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, 2019 and 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]	331	308.9	119	82.5	1,765	1,469.8	356	239.2
British Columbia[1]	1	0.2	-	-	443	411.8	167	152.5
Saskatchewan[1]	1	0.1	-	-	-	-	-	-
Total	**333**	**309.2**	**119**	**82.5**	**2,208**	**1,881.6**	**523**	**391.7**

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.

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

Landholdings

The following table sets out Tourmaline's developed and undeveloped properties as at December 31, 2019, in which Tourmaline has an interest. When determining gross and net acreage for two or more leases covering the same lands but different rights, the acreage is reported for each lease. When there are multiple discontinuous rights in a single lease, the acreage is reported only once.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	862,588	692,982	1,316,098	1,180,152	2,178,686	1,873,134
British Columbia	89,985	78,859	163,584	146,723	253,570	225,582
Saskatchewan	324	37	69,722	65,930	70,046	65,967
Total	**952,897**	**771,878**	**1,549,404**	**1,392,805**	**2,502,302**	**2,164,683**

Notes:

(1) Numbers may not add due to rounding.

Properties with no Attributable Reserves

The following table sets forth the gross and net acres of unproved properties held by Tourmaline as at December 31, 2019.

Unproved Properties as at December 31, 2019

	Gross Acres	Net Acres
Alberta	1,151,937	1,052,118
British Columbia	49,662	44,696
Saskatchewan	69,272	65,930
Total	**1,270,871**	**1,162,744**

The maximum net area for which the Company expects the rights to explore, develop and exploit to expire during 2020 is 283,938 acres in Alberta, 19,233 acres in British Columbia and 61 acres in Saskatchewan. The expiring acreage is continuously being evaluated and attempts will be made to maintain our rights on the acreage and mitigate expiries through land swaps, asset dispositions or drilling to maintain the lease. There are no material work commitments necessary to maintain these properties.

Significant Factors or Uncertainties Relevant to Properties With No Attributed Reserves

For information with respect to the Company's reclamation and abandonment obligations for the properties to which reserves have been attributed, see "*Additional Information Relating to Reserves Data – Significant Factors or Uncertainties Affecting Reserves Data*" in this Annual Information Form.

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 2024. Tourmaline has approximately $7.0 billion of tax pools available as at December 31, 2019, which can be used to offset taxable income in future years.

Capital Expenditures

The following table summarizes capital expenditures (including property acquisitions, net of dispositions, as well as capitalized general administrative expenses) related to Tourmaline's activities for the year ended December 31, 2019:

	$000s
Exploration, drilling and completions	743,397
Development, equipping and tie-in	171,875
Property acquisitions[1]	226,657
Property dispositions	(8,105)
Facilities	117,792
Geological and geophysical	-
Other (including capitalized G&A)	35,643
Total[2]	**1,287,259**

Notes:

(1) Property acquisitions are a result of approximately $168.5 million of acquired proved properties and approximately $58.2 million of acquired unproved properties.

(2) Includes capital expenditures related to Exshaw from January 1, 2019 to October 31, 2019 (without reduction to reflect the 9.4% third-party minority interest in Exshaw) and also includes capital expenditures related to Topaz from November 1, 2019 to December 31, 2019 (without reduction to reflect the 26% third-party minority interest in Topaz).

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, 2019:

	Exploratory Wells		**Development Wells**	
	Gross	**Net**	**Gross**	**Net**
Natural Gas	-	-	195	191.2
Oil	3	2.3	21	17.4
Service	-	-	-	-
Dry	-	-	-	-
Total[1]	**3**	**2.3**	**216**	**208.6**

Note:

(1) Includes wells in which Exshaw participated from January 1, 2019 to October 31, 2019 (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, 2020 as evaluated by GLJ and Deloitte, 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	**Conventional Natural Gas**	**Shale Natural Gas**	**Natural Gas Liquids**	**Oil Equivalent Total**
	Company Gross (Bbls/d)	**Company Gross (Mcf/d)**	**Company Gross (Mcf/d)**	**Company Gross (Bbls/d)**	**Company Gross (Boe/d)**
Proved Producing	8,139	776,203	425,900	40,374	248,863
Proved Developed Non-Producing	492	40,870	88,661	5,722	27,802
Proved Undeveloped	3,942	197,814	122,175	11,146	68,420
Total Proved	12,573	1,014,887	636,736	57,242	345,085
Total Probable	94	96,321	85,285	7,816	38,177
Total Proved Plus Probable	12,666	1,111,208	722,021	65,058	383,262

Notes:

(1) No one field accounted for 20% or more of Tourmaline's estimated 2020 total proved production in the Consolidated Reserve Report.
(2) Numbers may not add due to rounding.

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			
	2019(1)(2)(3)			
	March 31	**June 30**	**September 30**	**December 31**
Average Daily Production(4)				
Light and Medium Crude Oil (Bbl/d)	24,438	23,395	24,056	27,832
Conventional Natural Gas (Mcf/d)	1,015,357	957,066	917,294	925,580
Shale Natural Gas (Mcf/d)	423,855	414,259	485,174	514,166
NGL (Bbl/d)	29,127	28,598	31,777	32,054
Combined (Boe/d)	293,434	280,547	289,578	299,844
Average Price Received				
Light and Medium Crude Oil ($/Bbl)	62.29	75.49	71.92	65.08
Conventional Natural Gas ($/Mcf)	3.82	2.24	2.04	3.05
Shale Natural Gas ($/Mcf)	3.02	1.67	1.60	2.26
NGL ($/Bbl)	23.93	9.29	12.74	15.58
Combined ($/Boe)	25.15	17.37	16.52	21.01
Royalties Paid				
Light and Medium Crude Oil ($/Bbl)	5.79	7.19	6.93	6.65
Conventional Natural Gas ($/Mcf)(5)	0.02	(0.05)	(0.08)	(0.03)
Shale Natural Gas ($/Mcf)	0.31	0.08	0.01	0.07
NGL ($/Bbl)	1.93	0.89	1.25	1.62
Combined ($/Boe)	1.20	0.63	0.47	0.82
Production Costs (includes transportation)				
Light and Medium Crude Oil ($/Bbl)	14.74	12.96	13.97	14.19
Conventional Natural Gas ($/Mcf)	1.21	1.19	1.23	1.32
Shale Natural Gas ($/Mcf)	1.30	1.35	1.13	1.04
NGL ($/Bbl)(6)	-	-	-	-
Combined ($/Boe)	7.30	7.14	6.95	7.19
Netback Received ($/Boe)(7)	16.65	9.60	9.10	13.00

Notes:

(1) Includes Exshaw from January 1, 2019 to October 31, 2019 (without reduction to reflect the 9.4% third-party minority interest in Exshaw) and also includes Topaz from November 1, 2019 to December 31, 2019 (without reduction to reflect the 26% third-party minority interest in Topaz).
(2) Numbers may not add due to rounding.

(3) For the purposes of this disclosure, condensate has been combined with Light and Medium Crude Oil as the associated revenues and certain costs of condensate are similar to Light and Medium Crude Oil. Accordingly, NGLs in this disclosure exclude condensate.
(4) Before deduction of royalties.
(5) Includes royalty reductions for the quarters ended March 31, June 30, September 30 and December 31 of $0.11/Mcf, $0.13/Mcf, $0.14/Mcf and $0.14/Mcf, respectively, relating to the entire Alberta Gas Cost Allowance credits received by the Company.
(6) NGL volumes are derived from natural gas production, as such all the related operating costs are attributed to the production of natural gas.
(7) Netbacks are calculated by subtracting royalties and production costs from revenues.

The following table sets forth the average daily production volumes for the year ended December 31, 2019 for each of the important fields, aggregated by area, comprising Tourmaline's assets.

Area	**Light Crude Oil and Medium Crude Oil (bbl/d)**	**NGLs (bbl/d)**	**Conventional Natural Gas (Mcf/d)**	**Shale Natural Gas (Mcf/d)**	**Total (boe/d)**
Alberta Deep Basin	6,594	19,220	893,004	-	174,648
Other Alberta properties	7,933	1,249	60,474	-	19,261
British Columbia properties....................	10,410	9,932	-	459,682	96,956
Total[(1)(2)]	**24,937**	**30,401**	**953,478**	**459,682**	**290,865**

Note:

(1) Includes Exshaw from January 1, 2019 to November 10, 2019 (without reduction to reflect the 9.4% third-party minority interest in Exshaw).
(2) For the purposes of this disclosure, condensate has been combined with Light and Medium Crude Oil as the associated revenues and certain costs of condensate are similar to Light and Medium Crude Oil. Accordingly, NGLs in this disclosure exclude condensate

The Company's production for the year ended December 31, 2019 was 8.6% light and medium crude oil (including condensate), 10.5% NGLs, 54.6% conventional natural gas and 26.3% shale natural gas.

For the year ended December 31, 2019, approximately 37.3% of the Company's gross revenue was derived from crude oil production (including natural gas liquids), 45.9% was derived from conventional natural gas production and 16.7% was derived from shale natural gas production.

Forward Contracts and Marketing

The Company's commodity hedging policy has been established with the Board authorizing management to hedge up to 50% of current production. Other than as disclosed in the Financial Statements, 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. Refer to note 5(c) "*Financial Risk Management – Market Risk*" in the recently filed Consolidated Financial Statements of the Company as at and for the years ended December 31, 2019 and 2018 for further discussion on the Company's commodity hedging activities.

Tourmaline's transportation obligations or commitments for future physical deliveries of crude oil and natural gas are not expected to vary significantly from Tourmaline's future forecasted production.

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. As one of the largest natural gas producers in Canada, Tourmaline, which currently produces between 1.4 and 1.5 bcf/d, controls an estimated 9% percent of Western Canada's dry natural gas production and has a strong competitive position in its core areas (see "*Description of Core Long-Term Growth Areas*").

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, some 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 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 and Extreme Weather Conditions* ".

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*".

On November 8, 2017, the Board established a new Committee comprised of independent directors: the Environment, Sustainability and Safety Committee. The purpose of this Committee is to oversee policies relating to environment, health, safety and sustainability matters. Tourmaline leverages technology and innovative strategies to minimize its environmental impact, and in this regard, the Company has developed robust and integrated air emissions, water and land use strategies designed to reduce the impact of its operations on the environment. The Company's most recent Sustainability Report can be found on the Company's website at www.tourmalineoil.com.

Employees

At December 31, 2019, Tourmaline had 190 full time employees and 35 consultants located at its Calgary office, and 53 full time employees and 206 contract operators in various field locations. Tourmaline currently has

192 full time employees and 40 consultants located at its Calgary office, and 54 full time employees and 217 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 during the current financial year. No material reorganization is planned for the current financial year. See "*General Development of the Business*".

Environmental, Health and Safety Policies

Tourmaline 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. Tourmaline promotes safety and environmental awareness and protection through the implementation and communication of Tourmaline's environmental management and employee occupational health and safety programs, policies and procedures. Committee structures are established in Tourmaline'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.

Tourmaline 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. Tourmaline 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.

Tourmaline also faces environmental, health and safety risks in the normal course of its operations due to the handling and storage of hazardous substances. Tourmaline's environmental and occupational health and safety management systems are designed to manage such risks in Tourmaline'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

On March 6, 2018, the Board declared its first quarterly dividend of $0.08 per Common Share payable on March 29, 2018 to shareholders of record on March 14, 2018. Prior to such time, Tourmaline has never declared or paid any cash dividends on the Common Shares. Subsequent to its first quarterly dividend payment, Tourmaline increased its quarterly dividend by 25% to $0.10 per Common Share for the last two dividend payments of 2018 and further increased its quarterly dividend by 20% to $0.12 per Common Share for the last three dividend payments of 2019.

Dividend History

Date Paid	Amount per Common Share
March 29, 2018	$0.08
June 29, 2018	$0.09
September 28, 2018	$0.10
December 28, 2018	$0.10
March 29, 2019	$0.10
June 28, 2019	$0.12
September 30, 2019	$0.12

Dividend History

Date Paid	Amount per Common Share
December 31, 2019	$0.12

Tourmaline's intention will be to pay quarterly cash dividends on the Common Shares from its free cash flow (cash flow less total capital expenditures, including exploration and production capital and other corporate expenditures and excluding acquisition and core disposition activities, and is prior to dividend payments) to shareholders of record as of the dividend record date which is usually approximately 15 days prior to the dividend payment date. Tourmaline's dividend policy is intended to provide shareholders with relatively stable and predictable quarterly dividends, while retaining a portion of free cash flow to provide the Company with the financial flexibility to either reduce corporate debt, modify the development plan or pursue strategic acquisitions, as deemed appropriate.

In determining the level of dividends to be declared, the Board takes into consideration such factors as current and expected future levels of free cash flow (including income tax), capital expenditures, borrowings and debt repayments, changes in working capital requirements and other factors.

Over the long term, Tourmaline expects to continue to pay dividends from its free cash flow; however, credit facilities may be used to stabilize dividends from time to time. Growth capital expenditures will be funded from retained cash flow from operating activities, proceeds from asset dispositions and proceeds from additional debt or equity, as required. Although Tourmaline intends to continue to make regular quarterly dividends to shareholders, dividends are not guaranteed.

Notwithstanding the foregoing, the amount of future cash dividends declared and paid by Tourmaline, if any, will be subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates, compliance with any restrictions on the declaration and payment of dividends contained in any agreements to which Tourmaline is a party from time to time (including, without limitation, the agreements governing Tourmaline's credit facilities), and the satisfaction of liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends.

The Board intends to review this policy on a quarterly basis. Depending on the foregoing factors and any other factors that the Board deems relevant from time to time, many of which are beyond the control of the Board and Tourmaline's management team, the Board may change this policy following any such quarterly review or at any other time that the Board deems appropriate. Any such change may result in future cash dividends being reduced or suspended entirely.

The Board intends that dividends declared and paid by Tourmaline will qualify as "eligible dividends" for the purposes of the *Income Tax Act* (Canada) (and any similar applicable provincial legislation), and thus qualify for the enhanced gross-up and tax credit regime available to certain shareholders. The Board therefore intends to designate dividends paid by Tourmaline as "eligible dividends" and notify shareholders that dividends are "eligible dividends" for these purposes by posting a general notice to this effect on Tourmaline's website and by disclosing this fact in each press release that Tourmaline issues that contains a dividend announcement. Notwithstanding the foregoing, no assurances can be given that all dividends will qualify as "eligible dividends" and the designation of dividends as "eligible dividends" will be subject to the discretion of the Board.

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 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 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, 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 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 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
2019			
January	$19.44	$16.59	17,838,738
February	$21.27	$17.57	14,507,109
March	$22.20	$19.60	20,120,102
April	$22.62	$19.97	13,097,132
May	$20.50	$17.08	12,888,298
June	$17.69	$15.39	15,815,424
July	$17.81	$15.72	14,929,029
August	$16.48	$11.89	20,513,285
September	$15.12	$12.19	16,994,217
October	$13.23	$10.45	30,097,912
November	$13.47	$11.38	50,983,296
December	$15.46	$11.62	30,633,837

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 2019

Date of Issuance	Number of Options	Exercise Price of Options
January 15, 2019	154,500	$18.11
February 15, 2019	79,500	$19.05
March 15, 2019	102,000	$20.77
May 15, 2019	55,000	$19.75
June 15, 2019	59,250	$16.03
July 15, 2019	40,000	$16.60
August 15, 2019	58,000	$13.37
August 31, 2019	3,172,400	$12.60
October 15, 2019	65,000	$11.24
November 15, 2019	62,000	$12.57

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the Company's knowledge, as of December 31, 2019, 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, as at the date of this document, and principal occupation of the directors and 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 or State 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
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
Jill T. Angevine(1)(3)(6) Alberta, Canada	Director	Managing Director of Palisade Capital Management Ltd. since December 2018. Prior thereto, Vice President, Portfolio Manager at Matco Financial Inc. Prior thereto, Vice President and Director, Institutional Research at FirstEnergy Capital Corp.	November 4, 2015
William D. Armstrong(4)(6) 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 A. Baker(3)(4)(5)(6) Alberta, Canada	Director	Independent businessman since June 2016. Prior thereto, Mr. Baker was President and Chief Executive Officer of Nordegg Resources Inc., an oil and gas company, since March 2008. Prior to 2008, Mr. Baker was President and Chief Executive Officer of RSX Energy Inc., an oil and gas company.	March 22, 2011
John W. Elick(4)(5)(6) Alberta, Canada	Director	Non-Executive Chairman of Cinch from November 2001 to July 12, 2011 and Chief Executive Officer of Cinch from November 2001 to November 2009.	March 19, 2013
Andrew B. MacDonald(1)(2)(3)(6)(7) British Columbia, Canada	Director	Independent businessman since January 2009. Prior thereto, Co-Head of Canadian Equities and Portfolio Manager with Phillips, Hager & North Investment Management, an investment management company.	March 22, 2011
Lucy M. Miller(2)(3)(5)(6) Alberta, Canada	Director	Independent businesswoman since December 2016. Prior thereto, President and CEO of United Way of Calgary and Area since 2012 and prior thereto, Chief Superintendent of the Calgary Catholic School District.	June 7, 2017
Ron Wigham(1)(2)(4)(6) Alberta, Canada	Director	Independent Businessman since January 2014. Prior thereto Vice-Chairman of Peters & Co. Limited from October 2012, and prior thereto Managing Director, Capital Markets, Peters & Co. Limited.	March 7, 2016
Sherra Aspin Alberta, Canada	Vice President, Marketing	Vice President, Marketing of Tourmaline since September 2018. Prior thereto, Manager of Natural Gas Marketing of Tourmaline.	N/A
Allan J. Bush Alberta, Canada	Chief Operating Officer	Chief Operating Officer since May 2019. Prior thereto, Vice President, Operations and Chief Operating Officer since April 2014. Prior thereto, Vice President, Production and Completions since March 2013. Prior thereto, Completions and Operations Engineering Manager of Tourmaline and before that Completions and Operations Engineering Manager of Duvernay Oil Corp.	N/A

Name, Province or State and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director Since
Colin Frostad Alberta, Canada	Vice President, Exploration	Vice President, Exploration of Tourmaline since November 2019. Prior thereto, Exploration Manager and Senior Geologist at Tourmaline since 2009 and before that Geologist at 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
Earl H. McKinnon Alberta, Canada	Vice President, Operations	Vice President, Operations since may 2019. Prior thereto, Vice President, Drilling and Completions Operations of Tourmaline since May 2015. Prior thereto, Completions Manager of Tourmaline.	N/A
Sarah Tait Alberta, Canada	Controller	Controller of Tourmaline since September 2015. Prior thereto, Manager of Finance of Tourmaline and before that Chief Financial Officer of Cinch.	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

Notes:

(1) Member of the Audit Committee. Ms. Angevine is the Chair of the Audit Committee.
(2) Member of the Compensation Committee. Mr. Wigham is the Chair of the Compensation Committee.
(3) Member of the Corporate Governance and Nominating Committee. Mr. MacDonald is the Chair of the Corporate Governance and Nominating Committee.
(4) Member of the Reserves Committee. Mr. Baker is the Chair of the Reserves Committee.
(5) Member of the Environment, Safety and Sustainability Committee. Ms. Miller is the Chair of the Environment, Sustainability and Safety Committee.
(6) Independent director.
(7) Lead Director.

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.

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, 21.4 million Common Shares or approximately 7.9% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

To the knowledge of the Company, 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.

Bankruptcies

To the knowledge of the Company, other than as discussed below, 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.

Mr. Baker, a director of Tourmaline, served as President and Chief Executive Officer of Nordegg Resources Inc. ("**Nordegg**"), a private company, until June 10, 2016 and Mr. Rose, the President and Chief Executive Officer and a director of Tourmaline, served as a director of Nordegg until June 10, 2016. On June 16, 2016, a secured creditor of Nordegg was granted an order under the *Bankruptcy and Insolvency Act (Canada)* appointing a receiver to take possession and exercise control over all of Nordegg's current and future assets.

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 within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect Tourmaline.

AUDITOR, TRANSFER AGENT AND REGISTRAR

The Company's auditors are KPMG LLP, Chartered Professional Accountants, Suite 3100, 205 – 5th Avenue S.W., Calgary, Alberta T2P 4B9.

The transfer agent and registrar for the Common Shares is AST Trust Company (Canada). 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 Deloitte, 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 relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation.

INDUSTRY CONDITIONS

Companies carrying on business in the crude oil and natural gas sector in Canada are subject to extensive controls and regulations imposed through legislation of the federal government and the provincial governments in the jurisdictions where the companies have assets or operations. While such regulations do not affect the Company's operations in any manner that is materially different than the manner in which they affect other similarly-sized industry participants with similar assets and operations, investors should consider such regulations carefully. Although laws and regulations are a matter of public record, the Company is unable to predict what additional laws, regulations or amendments governments may enact in the future.

The Company holds interests in crude oil and natural gas properties, along with related assets, primarily in the Canadian provinces of Alberta, British Columbia and Saskatchewan. The Company's assets and operations are regulated by administrative agencies deriving authority from underlying legislation enacted by the applicable level of government. Regulated aspects of the Company's upstream crude oil and natural gas business include all manner of activities associated with the exploration for and production of crude oil and natural gas, including, among other matters: (i) permits for the drilling of wells; (ii) technical drilling and well requirements; (iii) permitted locations and access of operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct crude oil and natural gas operations and remain in good standing with the applicable federal or provincial regulatory scheme, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance in this regard can be costly and a breach of the same may result in fines or other sanctions. The discussion below outlines certain pertinent conditions and regulations that impact the crude oil and natural gas industry in Western Canada.

Pricing and Marketing in Canada

Crude Oil

Producers of crude oil are entitled to negotiate sales contracts directly with crude oil purchasers. As a result, macroeconomic and microeconomic market forces determine the price of crude oil. Worldwide supply and demand factors are the primary determinant of crude oil prices; however, regional market and transportation issues also influence prices. The specific price depends, in part, on crude oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Natural Gas

Negotiations between buyers and sellers determines the price of natural gas sold in intra-provincial, interprovincial and international trade. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Natural Gas Liquids

The pricing of condensates and other NGLs such as ethane, butane and propane sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such prices depend, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms.

Exports from Canada

On August 28, 2019, Bill C-69 came into force, replacing, among other things, the *National Energy Board Act* (the "**NEB Act**") with the *Canadian Energy Regulator Act* (Canada) (the "**CERA**"), and replacing the National Energy Board (the "**NEB**") with the Canadian Energy Regulator ("**CER**"). The CER has assumed the NEB's responsibilities broadly, including with respect to the export of crude oil, natural gas and NGLs from Canada. The legislative regime relating to exports of crude oil, natural gas and NGL from Canada has not changed substantively under the new regime.

Exports of crude oil, natural gas and NGLs from Canada are subject to the CERA and remain subject to the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the "**Part VI Regulation**"). While the Part VI Regulation was enacted under the NEB Act, it will remain in effect until 2022, or until new regulations are made under the CERA. The CERA and the Part VI Regulation authorize crude oil, natural gas and NGLs exports under either short-term orders or long-term licences. For natural gas, the maximum duration of an export licence is 40 years; for crude oil and other gas substances (e.g. NGLs), the maximum term is 25 years. To obtain a crude oil export licence, a mandatory public hearing with the CER is required; however, there is no public hearing requirement for the export of natural gas and NGLs. Instead, the CER will continue to apply the NEB's written process that includes a public comment period for impacted persons. Following the comment period, the CER completes its assessment of the application and either approves or denies the application. The CER can approve an application if it is satisfied that proposed export volumes are not greater than Canada's reasonably foreseeable needs, and if the proposed exporter is in compliance with the CERA and all associated regulations and orders made under the CERA. Following the CER's approval of an export licence, the federal Minister of Natural Resources is mandated to give his or her final approval. While the Part VI Regulation remains in effect, approval of the cabinet of the Canadian federal government ("**Cabinet**") is also required. The discretion of the Minister of Natural Resources and Cabinet will be framed by the Minister of Natural Resources' mandate to implement the CERA safely and efficiently, as well as the purpose of the CERA, to effect "oil and natural gas exploration and exploitation in a manner that is safe and secure and that protects people, property and the environment".

The CER also has jurisdiction to issue orders that provide a short-term alternative to export licences. Orders may be issued more expediently, since they do not require a public hearing or approval from the Minister of Natural Resources or Cabinet. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGLs) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m^3 per day.

As to price, exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the CER and the federal government.

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGLs outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation projects are underway, many contemplated projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Major pipeline and other transportation infrastructure projects typically require a significant length of time to complete once all regulatory and other hurdles have been cleared. In addition, production of crude oil, natural gas and NGLs in Canada is expected to continue to increase, which may further exacerbate the transportation capacity deficit.

Transportation Constraints and Market Access

Pipelines

Producers negotiate with pipeline operators (or other transport providers) to transport their products to market on a firm or interruptible basis. Transportation availability is highly variable across different jurisdictions and regions. This variability can determine the nature of transportation commitments available, the number of potential customers that can be reached in a cost-effective manner and the price received. Due to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced low commodity pricing relative to other markets in the last several years.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require a regulatory review and approval by Cabinet. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. The federal government amended the federal approval process with the CER, which aims to create efficiencies in the project approval process while upholding stringent environmental and regulatory standards. However, as the CER has not yet undertaken a major project approval, it is unclear how the new regulator operates compared to the NEB and whether it will result in a more efficient approval process. Lack of regulatory certainty is likely to influence investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments. Additional delays causing further uncertainty result from legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples, and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines require approvals of several levels of government in the United States.

In the face of such regulatory uncertainty, the Canadian crude oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGLs, including pipelines, rail, trucks and marine transport. Improved access to global markets through the Midwest United States and export shipping terminals on the west coast of Canada could help to alleviate downward pressure on commodity prices. Several proposals have been announced to increase pipeline capacity from Western Canada to Eastern Canada, the United States, and other international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other factors related to transportation and export infrastructure have led to the delay, suspension or cancellation of a number of pipeline projects.

With respect to the current state of the transportation and exportation of crude oil from Western Canada to domestic and international markets, the Enbridge Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, formerly expected to be in-service in late 2019, continues to experience permitting difficulties in the United States and is now expected to be in-service in the latter half of 2020. The Canadian portion of the replaced pipeline began commercial operation on December 1, 2019.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of sustained political opposition in British Columbia, the federal government purchased the Trans Mountain Pipeline from Kinder Morgan Cochin ULC in August 2018. However, the Trans Mountain Pipeline expansion experienced a setback when, in August 2018, the Federal Court of Appeal identified deficiencies in the NEB's environmental assessment and the Government's Indigenous consultations. The Court quashed the accompanying certificate of public convenience and necessity and directed Cabinet to correct these deficiencies. On June 18, 2019, Cabinet re-approved the Trans Mountain Pipeline expansion and directed the NEB to issue a certificate of public convenience and necessity for the project. Ongoing opposition by Indigenous groups continues to affect the progress of the Trans Mountain Pipeline. Along with its approval of the expansion, the federal government also announced the launch of the first step of a multi-step process of engagement with Indigenous groups for potential Indigenous economic participation in the pipeline. Following a public comment period initiated after the approval, the NEB ruled that NEB decisions and orders issued prior to the Federal Court of Appeal decision quashing the original Certificate of Public Convenience and Necessity will remain valid unless the CER (having replaced the NEB) decides that relevant circumstances have materially changed, such that there is a doubt as to the correctness of a particular decision or order. Construction commenced on the Trans Mountain Pipeline in late 2019, and is proceeding concurrently alongside CER hearings with landowners and affected communities to determine the final route for the Trans Mountain Pipeline.

In December 2019, the Federal Court of Appeal heard a judicial review application brought by six Indigenous applicants challenging the adequacy of the federal government's further consultation on the Trans Mountain Pipeline expansion. Two First Nations subsequently withdrew from the litigation after reaching a deal with Trans Mountain. On February 4, 2020, the Federal Court of Appeal dismissed the remaining four appellants' application for judicial review, upholding Cabinet's second approval of the Trans Mountain Pipeline expansion from June 2019.

In addition, on April 25, 2018, the British Columbia Government submitted a reference question to the British Columbia Court of Appeal, seeking to determine whether it has the constitutional jurisdiction to amend the *Environmental Management Act* (the "**BC EMA**") to impose a permitting requirement on carriers of heavy crude within British Columbia. The British Columbia Court of Appeal answered the reference question unanimously in the negative, and on January 16, 2020, the Supreme Court of Canada heard the Attorney General of British Columbia's appeal. The Supreme Court of Canada unanimously dismissed the appeal and adopted the reasons of the British Columbia Court of Appeal. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – British Columbia*".

While it was expected that construction on the Keystone XL Pipeline, owned by the Canadian company TC Energy Corporation ("**TC Energy**") would commence in the first half of 2019, pre-construction work was halted in late 2018 when a United States Federal Court Judge determined the underlying environmental review was inadequate. The United States Department of State issued its final Supplemental Environmental Impact Statement in late 2019, and in January 2020, the United States Government announced its approval of a right-of-way that would allow the Keystone XL Pipeline to cross 74 kilometers of federal land. TC Energy announced in January 2020 that it plans to begin mobilizing heavy equipment for pre-construction work in February 2020, and that work on pipeline segments in Montana and South Dakota will begin in August 2020. Nevertheless, the Keystone XL pipeline remains subject to legal and regulatory barriers. In December 2019, a federal judge in Montana rejected the United States Government's request to dismiss a lawsuit by Native American tribes attempting to block required pipeline permits. The tribes claim that a permit issued in March 2019 would allow the pipeline to disturb cultural sites and water supplies in violation of tribal laws and treaties. Furthermore, the 1.9-kilometer long segment of the pipeline that will cross the Canada-United States Border remains dependant on the receipt of a grant of right-of-way and temporary use permit from the United States Bureau of Land Management and other related federal land authorizations.

Marine Tankers

Bill C-48 received royal assent on June 21, 2019, enacting the *Oil Tanker Moratorium Act*, which imposes a ban on tanker traffic transporting certain crude oil and NGLs products in excess of 12,500 metric tones to or from British Columbia's north coast. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Federal*".

Crude Oil and Bitumen by Rail

On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 bbls/day of crude oil out of the province to help alleviate the high price differential plaguing Canadian oil prices. The Alberta Petroleum Marketing Commission would purchase crude oil from producers and market it, using the expanded rail capacity to transport the marketed oil to purchasers. However, in the spring of 2019, the Government of Alberta indicated that the rail program will be cancelled by assigning the transportation contracts to industry proponents. On February 11, 2020, the Government of Alberta announced that it had sold $10.6 billion worth of crude-by-rail contracts to the private sector.

In February 2020, the federal government announced that trains hauling more than 20 cars carrying dangerous goods, including crude oil and diluted bitumen, would be subject to reduced speed limits, following two derailments that led to fires and oil spills in Saskatchewan. These reduced speed limits will remain in effect until April 1, 2020.

Natural Gas

Natural gas prices in Alberta and British Columbia have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. Companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing. Companies without firm access may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production).

Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline network, (which carries much of Alberta's gas production) to give priority to deliveries into storage. The change has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system. January 2020 has seen the narrowest price differential between Canadian and United States Natural Gas benchmarks since early 2019.

Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, with 24 export licences issued since 2011, government decision-making, regulatory uncertainty, opposition from environmental and Indigenous groups, and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, In October 2018, the joint venture partners of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project, which will allow LNG Canada to transport natural gas from northeastern British Columbia to the LNG Canada liquefaction facility and export terminal in Kitimat, BC, via the Coastal GasLink pipeline, which will be built and operated by TC Energy's subsidiary Coastal GasLink ("**CGL**") (the "**CGL Pipeline**"). Pre-construction activities began in November 2018, with a completion target of 2025. In late 2019, TC Energy announced that it would sell 65% of its interest in the CGL Pipeline, to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. The transaction is expected to close in the first half of 2020. The CGL Pipeline's route was altered as a result of feedback that LNG Canada received from Indigenous groups in the area, and on May 1, 2019, the British Columbia Oil and Gas Commission (the "**BC Commission**") approved the current planned route for the CGL Pipeline. However, the CGL Pipeline has faced intense opposition. For example, a challenge to the approval process of the CGL Pipeline was launched in August 2018, contending that it should have been subject to the federal review instead of a provincial review. In July 2019, the NEB confirmed that the CGL Pipeline was properly subject to provincial jurisdiction. In addition, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have caused delays of construction activities on the CGL Pipeline. Coastal Gaslink Pipeline Ltd. obtained an injunction on December 31, 2019, and enforcement of the injunction started in February 2020.

On February 19, 2020, the British Columbia Environmental Assessment Office (the "**EAO**") directed CGL to re-engage and consult further with Unist'ot'en, one of the Wet'suwet'en clans opposed to the pipeline route, regarding the impacts of the pipeline on a nearby healing centre. The EAO prescribed a 30-day timeline for the completion of these consultations and CGL is permitted to continue pre-construction work in the relevant area.

In December 2019, the CER approved a 40-year export licence for the Kitimat LNG project, a proposed joint venture between Chevron Canada Limited and Woodside Energy International (Canada Limited), a subsidiary of Australian Energy Ltd. This licence remains subject to Cabinet approval, and Chevron Canada Limited has indicated that it is interested in selling its 50 percent interest in Kitimat LNG. The Woodfibre LNG Project is a small-scale LNG processing and export facility near Squamish, British Columbia. The BC Commission approved a project permit for Woodfibre LNG, a subsidiary of Singapore-based Pacific Oil and Gas Ltd. in July 2019. Pre-construction agreements for Woodfibre LNG are in the process of being finalized. A project by GNL Québec Inc. is working through the federal impact assessment process for the construction and operation of a LNG facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River. The Goldboro LNG project, located in Nova Scotia, proposed by Pieridae Energy Ltd., would see LNG exported from Canada to European markets. Pieridae has agreements with Shell, upstream, and with Uniper, a German utility, downstream. The federal government has issued Goldboro LNG a 20-year export licence, and Pieridae Energy Ltd. has forecast a positive final investment decision for 2020. The Cedar LNG Project near Kitimat by Cedar LNG Export

Development Ltd. is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office conducting the environmental assessment on behalf of the Impact Assessment Agency of Canada ("**IA Agency**").

Enbridge Open Season

In early August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier pipeline system, wherein producers could nominate volumes to ship through the pipeline. The changes that Enbridge intends to implement in the open season include the transition of the mainline system from a common carrier to a primarily contract carrier pipeline, wherein producers will have to commit to reserved space in the pipeline for a fixed term, with only 10% of available capacity reserved for nominations. As a result, shippers seeking firm capacity on the Enbridge system would no longer be able to rely on the nomination process and would have to enter long-term contracts for service.

Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without prior regulatory approval. Following an expedited hearing process, the CER decided to shut down the open season, citing concerns about fairness and uncertainty regarding the ultimate terms and conditions of service.

On December 19, 2019, Enbridge applied to the CER for a hearing for the right to hold an open season. The CER is expected to establish a timeline for the process in early 2020. Interveners will have the opportunity to make written submissions, and then an oral hearing will take place later in the year. A final decision from the CER is expected in early 2021.

Curtailment

On December 2, 2018, the Government of Alberta announced that, commencing January 1, 2019, it would mandate a short-term reduction in provincial crude oil and crude bitumen production. As contemplated in the *Curtailment Rules*, as amended effective October 1 2019, the Government of Alberta, on a monthly basis, subjects crude oil producers producing more than 20,000 bbls/d to curtailment orders that limit their production according to a pre-determined formula that allocates production limits proportionately amongst all operators subject to curtailment orders.

Where an operator to whom a curtailment order applies is a joint venture or partnership, the partners or joint venturers may enter into an agreement respecting the allocation of the combined production among themselves to comply with the curtailment order.

Curtailment first took effect on January 1, 2019, limiting province-wide production of crude oil and crude bitumen to 3.56 million bbls/d. The curtailment rate dropped gradually over the course of 2019 as a result of decreasing price differentials and volumes of crude oil and crude bitumen in storage. Allowable production for December 2019, January 2020 and February 2020 is set at 3.81 million bbls/d.

The Government of Alberta introduced certain policy changes to the curtailment program in late 2019, including giving the Minister of Energy the power to set revised production limits for a producer following a merger or acquisition, and creating an exemption for newly drilled conventional oil wells. Furthermore, the Government of Alberta created a special production allowance, effective October 28, 2019, that allows crude oil production in excess of a curtailment order, provided that the extra production is shipped out of Alberta by rail.

Curtailment volumes affect sixteen of over 300 producers in Alberta. The *Curtailment Rules* are set to be repealed by December 31, 2020.

The Company is not currently subject to a curtailment order.

The North American Free Trade Agreement and Other Trade Agreements

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. The three NAFTA signatories have been working towards replacing NAFTA. On November 30, 2018, Canada, Mexico, and the United States signed a new trade agreement, widely referred to as the United States Mexico Canada Agreement (the "**USMCA**"), sometimes referred to as the Canada United States Mexico Agreement, or "**CUSMA**". Legislative bodies in the three signatory countries must ratify the USMCA before it comes into force. Mexico's senate ratified the USMCA in June 2019. In late December 2019, the United States' House of Representatives approved the USMCA, and the USMCA received approval from the United States Senate on January 16, 2020. On January 29, 2020, the Government of Canada tabled Bill C-4 to ratify the USMCA. According to Bill C-4, the USMCA will come into force two months after the House of Commons and the Senate pass Bill C-4. Until then, NAFTA remains the North American trade agreement currently in force. As the United States remains Canada's primary trading partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada the implementation of the final version ratified version of the USMCA could have an impact on Western Canada's crude oil and natural gas industry at large, including the Company's business.

Under the terms of NAFTA's Article 605, a proportionality clause prevents Canada from implementing policies that limit exports to the United States and Mexico, relative to the total supply produced in Canada. Canada remains 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 Canada 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. Further, all three signatory countries are prohibited from imposing a minimum or maximum price requirement on exports (where any other form of quantitative restriction is prohibited) and imports (except as permitted in the enforcement of countervailing and anti-dumping orders and undertakings). NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of such changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements.

The Government of Alberta's curtailment program complies with NAFTA's Article 605, under which Canada must make available a consistent proportion of the crude oil and bitumen produced to the other NAFTA signatories. As a result of the proportionality rule, reducing Canadian supply reduced the required offering under NAFTA, with the result that the amount of crude oil and bitumen that Canada is required to offer, while Canadian crude oil prices are depressed, may be reduced. It is possible that the USMCA will come into force before the Government of Alberta's curtailment order is set to be repealed by the end of 2020.

The USMCA does not contain the proportionality rules of NAFTA's Article 605. The elimination of the proportionality clause removes a barrier in Canada's transition to a more diversified export portfolio. While diversification depends on the construction of infrastructure allowing more Canadian production to reach Eastern Canada, Asia, and Europe, the USMCA may allow for greater export diversification than currently exists under NAFTA.

Other Trade Agreements

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries while in other circumstances Canada has been unsuccessful in its efforts. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("**CETA**"), which provides for duty-free, quota-free market access for Canadian crude oil and natural gas products to the European Union. Although CETA remains subject to ratification by 14 of the 28 national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In light of the United Kingdom's departure from the European Union on January 31, 2020, the United Kingdom and Canada are expected to work towards a new trade agreement through the 11-month implementation period, during which the United Kingdom will transition out of the European Union. As such, CETA will remain in place until December 31, 2020.

Canada and ten other countries have agreed on the text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The CPTPP is in force among the first seven countries to ratify the agreement – Canada, Australia, Japan, Mexico, New Zealand, Vietnam, and Singapore.

While it is uncertain what effect CETA, CPTPP, or any other trade agreements will have on the crude oil and natural gas industry in Canada, the lack of available infrastructure for the offshore export of crude oil and natural gas may limit the ability of Canadian crude oil and natural gas producers to benefit from such trade agreements.

Land Tenure

The respective provincial governments (i.e. the Crown), predominantly own the mineral rights to crude oil and natural gas located in Western Canada, with the exception of Manitoba (which only owns 20% of the mineral rights). Provincial governments grant rights to explore for and produce crude 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. The provincial governments in Western Canada's provinces conduct regular land sales where crude oil and natural gas companies bid for leases to explore for and produce crude oil and natural gas pursuant to mineral rights owned by the respective provincial governments. Oil and natural gas leases generally have a fixed term; however, a lease may generally be continued after the initial term where certain minimum thresholds of production have been reached, all lease rental payments have been paid on time and other conditions are satisfied.

To develop crude oil and natural gas resources, it is necessary for the mineral estate owner to have access to the surface lands as well. Each province has developed its own process for obtaining surface access to conduct operations that operators must follow throughout the lifespan of a well, including notification requirements and providing compensation for affected persons for lost land use and surface damage.

Each of the provinces of Western Canada have 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 licence. In addition, Alberta has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for new leases and licences. British Columbia has a policy of "zone specific retention" that allows a lessee to continue to lease for zones in which they can demonstrate the presence of oil or natural gas, with the remainder reverting to the Crown.

In addition to Crown ownership of the rights to crude oil and natural gas, private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. In the provinces of Alberta, British Columbia, Saskatchewan and Manitoba, approximately 19%, 6%, 20% and 80%, respectively, of the mineral rights are owned by private freehold owners. Rights to explore for and produce such crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and crude oil and natural gas explorers and producers.

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within Indigenous reservations designated under the *Indian Act* (Canada). Indian Oil and Gas Canada ("**IOGC**"), which is a federal government agency, manages subsurface and surface leases, in consultation with the applicable Indigenous peoples, for exploration and production of crude oil and natural gas on Indigenous reservations.

Until recently, oil and natural gas activities conducted on Indian reserve lands were governed by the *Indian Oil and Gas Act* (the "**IOGA**") and the *Indian Oil and Gas Regulations, 1995* (the "**1995 Regulations**"). In 2009, Parliament passed *An Act to Amend the Indian Oil and Gas Act*, amending and modernizing the IOGA (the "**Modernized IOGA**"), however the amendments were delayed until the federal government was able to complete stakeholder consultations and update the accompanying Regulations (the "**2019 Regulations**"). The Modernized IOGA and the 2019 Regulations came into force on August 1, 2019. At a high level, the Modernized IOGA and the 2019 Regulations govern both surface and subsurface IOGC Leases, establishing the terms and conditions with which an IOGC leaseholder must comply. The two enactments also establish a substitution system whereby provincial oil and natural gas/environmental regulatory authorities act on behalf of the federal government to ensure greater symmetry between federal and provincial regulatory standards. The Company does not have operations on Indian reserve lands.

Royalties and Incentives

General

Each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects and crude oil, natural gas and NGLs production. Royalties payable on production from lands where the Crown does not hold the mineral rights 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 provincial regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable typically depends in part on prescribed reference prices, well productivity, geographic location, field discovery date, method of recovery and the type or quality of the petroleum substance produced.

Occasionally the governments of Western Canada's provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low, to encourage exploration and development activity. In addition, such programs may be introduced to encourage producers to undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGLs.

The federal government also announced in late 2018 that it would make $1.6 billion available to the oil and natural gas industry in light of worsening commodity price differentials. The aid package has been administered through federal agencies including the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, and Innovation, Science and Economic Development Canada. Export Development Canada has lent or guaranteed $629 million among 37 companies, of $1 billion available to oil and natural gas producers. The Bank of Canada has made 892 loans totalling $207.5 million out of its $500-million commercial loan allotment in the aid package. Innovation, Science and Economic Development Canada announced $49 million each for two projects to help Alberta companies building facilities to turn propane into polypropylene, a type of plastic not currently produced in Canada, but often used in packaging and labels. Natural Resources Canada distributed $37 million of a $50-million commitment under its Clean Growth Program for nine projects that help oil and natural gas companies reduce their carbon footprints.

Producers and working interest owners of crude oil and natural gas rights may also carve out additional royalties or royalty-like interests through non-public transactions, which include the creation of instruments such as overriding royalties, net profits interests and net carried interests.

Alberta

In Alberta, provincially-set royalty rates apply to Crown-owned mineral rights. In 2016, the Government of Alberta adopted a modernized royalty framework (the "**Modernized Framework**") that applies to all wells drilled after December 31, 2016. The previous royalty framework (the "**Old Framework**") will continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework. The Royalty Guarantee Act (Alberta), came into effect on July 18, 2019, and provides that no major changes will be made to the current oil and natural gas royalty structure for a period of at least 10 years.

The Modernized Framework applies to all hydrocarbons other than oil sands which will remain subject to their existing royalty regime. Royalties on production from non-oil sands wells under the Modernized Framework are determined on a "revenue-minus-costs" basis with the cost component based on a Drilling and Completion Cost Allowance formula for each well, depending on its vertical depth and/or horizontal length. The formula is based on the industry's average drilling and completion costs as determined by the Alberta Energy Regulator (the "**AER**") on an annual basis.

Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues of between 5% and 40% for crude oil and pentanes and 5% and 36% for methane, ethane, propane and butane, all determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward towards a minimum of 5% as the mature well's production declines. As the Modernized Framework uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low cost producers benefit if their well costs are lower than the Drilling and Completion Cost Allowance and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

Oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis. The Crown's royalty share of production is payable monthly, and producers must submit their records showing the royalty calculation. The *Mines and Minerals Act* was amended in 2014, and shortened the window during which producers can submit amendments to their royalty calculations before they become statute-barred, from four years to three. Both the 2014 and 2015 production years became statute barred on December 31, 2018 as the pre-amendment four-year period applied for the years up to and including 2014. Going forward, producers will only have three years to amend their royalty calculations.

The Old Framework is applicable to all conventional crude oil and natural gas wells drilled prior to January 1, 2017 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional crude oil production under the Old Framework range from a base rate of 0% to a cap of 40%. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%. The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 metres deep, as well as the acid gas content of the produced gas. Under the Old Framework, the royalty rate applicable to NGLs is a flat rate of 40% for pentanes and 30% for butanes and propane. Currently, producers of crude oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of crude oil and natural gas produced.

Oil sands production is also subject to Alberta's royalty regime. The Modernized Framework did not change the oil sands royalty framework. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% and 9% depending on the market price of crude oil, determined using the average monthly price, expressed in Canadian dollars, for Western Texas Intermediate crude oil at Cushing, Oklahoma. Rates are 1% when the market price of crude oil is less than or equal to $55 per barrel and increase for every dollar of market price of crude oil increase to a maximum of 9% when crude 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 between 1% and 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 crude oil increase above $55 up to 40% when crude oil is priced at $120 or higher.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage crude oil and natural gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including as applied to coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells.

Freehold mineral taxes are levied for production from freehold mineral lands on an annual basis on calendar year production. Freehold mineral taxes are calculated using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. On average, in Alberta the tax levied is 4% of revenues reported from freehold mineral title properties. The freehold mineral taxes would be in addition to any royalty or other payment paid to the owner of such freehold mineral rights, which are established through private negotiation.

British Columbia

Producers of crude oil in British Columbia receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. The royalty calculation takes into account the production of crude oil on a well-by-well basis, which can be up to 40%, based on factors such as the volume of crude oil produced by the well or tract and the crude oil vintage, which depends on density of the substance and when the crude oil pool was located. Royalty rates are reduced on low-productivity wells and other wells with applicable royalty exemptions to reflect higher per-unit costs of exploration and extraction.

Producers of natural gas and NGLs in British Columbia receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. Different royalty rates apply for natural gas, NGLs and natural gas by-products. For natural gas, the royalty rate can be up to 27% of the value of the natural gas and is based on whether the gas is classified as conservation gas or non-conservation gas, as well as reference prices and the select price. For NGLs and condensates, the royalty rate is fixed at 20%.

The royalties payable by each producer will therefore vary depending on the types of wells and the characteristics of the substances being produced. Additionally, the Government of British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity natural gas wells. These include both royalty credit and royalty reduction programs.

Producers of crude oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For crude oil, the applicable freehold production tax is based on the volume of monthly production, which is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the applicable freehold production tax is a flat rate, or, at certain production levels, is determined using a sliding scale formula based on a reference price, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold NGLs is a flat rate of 12.25%. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax that is equivalent to $4.94 per hectare of producing lands. Non-producing lands are taxed on a sliding scale from $1.25 to $4.94 per hectare, depending on the total number of hectares owned by the entity.

Saskatchewan

In Saskatchewan, the Crown owns approximately 80% of the crude oil and natural gas rights, with the remainder being freehold lands. For Crown lands, taxes (the "**Resource Surcharge**") and royalties are applicable to revenue generated by entities focused on crude oil and natural gas operations. The Resource Surcharge rate is 3% of the value of sales of all crude oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For crude oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales. Additionally, a mineral rights tax is charged to mineral rights holders paid on an annual basis at the rate of $1.50 per acre owned regardless of whether or not there is production from the lands.

In addition to such surcharges and taxes, the Crown royalty rate payable in respect of crude oil, depends on a number of variables including, the type and vintage of crude oil, the quantity of crude oil produced in a month, the average wellhead price and certain price adjustment factors determined monthly by the provincial government. This means that producers may pay varying royalties each month, depending on monthly production, governmental price adjustments and the underlying characteristics of the producer's assets. Where production equals the relevant reference well production rate, the minimum Crown royalty rate payable ranges from 5% to 20% and the maximum royalty rate payable ranges from 30% to 45%, depending on the classification of the crude oil, the average wellhead price and is subject to applicable deductions.

The amount payable as a Crown royalty in respect of production of natural gas and NGLs is determined by a sliding scale based on the monthly provincial average gas price published by the Government of Saskatchewan, the quantity produced in a given month, the type of natural gas, the classification of the natural gas and the finished drilling date of the respective well. Similar to crude oil royalties, the royalties payable on natural gas will range from 5% to 20%, and additional marginal royalty rates may apply between 30% to 45%, where average wellhead prices are above base prices. Again, this means that producers may pay varying royalties each month, depending on pricing factors, governmental adjustments and the underlying characteristics of the producer's assets.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, with targeted programs in effect for certain vertical crude oil wells, exploratory gas wells, horizontal crude oil and natural gas wells, enhanced crude oil recovery wells and high water-cut crude oil wells.

For production from freehold lands, producers must pay a freehold production tax, determined by first determining the Crown royalty rate, and then subtracting a calculated production tax factor. Depending on the classification of the petroleum substance produced, this subtraction factor may range between 6.9 and 12.5, however, in certain circumstances, the minimum rate for freehold production tax can be zero. This means that the ultimate tax payable to the Crown by producers on freehold lands will vary based on the underlying characteristics of the producer's assets.

Freehold and Other Types of Non-Crown Royalties

Royalties on production from privately-owned freehold lands are negotiated between the mineral freehold owner and the lessee under a negotiated lease or other contract. Producers and working interest participants may also pay additional royalties to parties other than the mineral freehold owner where such royalties are negotiated through private transactions.

In addition to the royalties payable to the mineral owners (or to other royalty holders if applicable), producers of crude oil and natural gas from freehold lands in each of the Western Canadian provinces are required to pay freehold mineral taxes or production taxes. Freehold mineral taxes or production taxes are taxes levied by a provincial government on crude oil and natural gas production from lands where the Crown does not hold the mineral rights. A description of the freehold mineral taxes payable in each of the Western Canadian provinces is included in the above descriptions of the royalty regimes in such provinces.

Where oil and natural gas leases fall under the jurisdiction of the IOGC, the IOGC is responsible for issuing crude oil and natural gas agreements between Indigenous groups and producers, and collecting and distributing royalty revenues. The exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific Indigenous group. Ultimately, the relevant Indigenous group must approve the royalty rate for each lease.

Regulatory Authorities and Environmental Regulation

General

The Canadian crude oil and natural gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial, and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain crude oil and natural gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment, and reclamation of well, facility and pipeline sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability, and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas ("**GHG**") emissions including carbon dioxide equivalents ("**CO_2e**"), may impose further requirements on operators and other companies in the crude oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of both the federal and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport including interprovincial pipelines.

On August 28, 2019, with the passing of Bill C-69, the CERA and the *Impact Assessment Act* ("**IAA**") came into force and the NEB Act and the *Canadian Environmental Assessment Act*, *2012* ("**CEAA 2012**") were repealed. In addition, the IA Agency replaced the Canadian Environmental Assessment Agency ("**CEA Agency**").

Bill C-69 introduced a number of important changes to the regulatory regime for federally regulated major projects and associated environmental assessments. Previously, the NEB administered its statutory jurisdiction as an integrated regulatory body. Now, the CERA separates the CER's administrative and adjudicative functions. A board of directors and a chief executive officer will manage strategic, administrative and policy considerations while adjudicative functions will fall into the purview of a group of independent commissioners. The CER has assumed the jurisdiction previously held by the NEB over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and offshore renewable energy projects, including offshore wind and tidal facilities. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of these projects, culminating in their eventual abandonment.

Designated projects under the IAA include interprovincial or international pipelines that require more than 75km of new right of way, and will require an impact assessment as part of their regulatory review. The impact assessment, conducted by a review panel, jointly appointed by the CER and the IA Agency, includes expanded criteria the review panel may consider when reviewing an application. The impact assessment also requires consideration of the project's potential adverse effects, the overall societal impact and the expanded public interest that a project may have. The impact assessment must look at the direct result of the project's construction and operation, including environmental, biophysical and socio-economic factors, including consideration of a gender-based analysis, climate change, and impacts to Indigenous rights. Designated projects include pipelines that require more than 75km of new right of way and pipelines located in national parks. Large scale in situ oil sands projects not regulated by provincial greenhouse gas emissions and certain refining, processing and storage facilities will also require an impact assessment.

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process. Applications for non-designated projects will follow a similar process as under the NEB Act. There is significant uncertainty surrounding the impact of Bill C-69 on oil and natural gas projects. There was significant opposition from industry and others in respect of Bill C-69, and notwithstanding its stated purpose, there is concern that the changes brought about by Bill C-69 will result in projects not being approved or increased delays in approvals. The Minister of Natural Resources has a mandate to implement the CER efficiently and effectively, but the CER's ability to expedite the project approval process has not yet been substantially tested.

On May 12, 2017, the federal government introduced Bill C-48 in Parliament. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. Parliament passed Bill C-48 as the *Oil Tanker Moratorium Act* which received royal assent on June 21, 2019. The enactment of this statute may prevent pipelines from being built, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium (north of 50°53′00″ north latitude and west of 126°38′36″ west longitude) and, as a result, may negatively impact the ability of producers to access global markets.

Alberta

The AER is the principal regulator responsible for all energy resource development in Alberta. It derives its authority from the *Responsible Energy Development Act* and a number of related legislation including the *Oil and Gas Conservation Act* (the "**OGCA**"), the *Oil Sands Conservation Act*, the *Pipeline Act*, and the *Environmental Protection and Enhancement Act*. The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as the Alberta Ministry of Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is intended to be efficient, attractive to business and investors and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. Its approach to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including the Alberta Ministry of Environment and Parks, the Alberta Ministry of Energy, the Aboriginal Consultation Office and the Land Use Secretariat.

The Government of Alberta's land-use policy for surface land in Alberta sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land-use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. As a result, several regional plans have been implemented. These regional plans may affect further development and operations in such regions.

The AER monitors seismic activity across Alberta, in the context of assessing the risks associated with, and instances of, earthquakes induced by hydraulic fracturing. Hydraulic fracturing is an important and common practice to stimulate production of oil and gas from dense subsurface rock formations. The process involves the injection of water, sand or other proppants and additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate oil and gas production. The Company routinely conducts hydraulic fracturing in its drilling and completion programs. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, prompting regulatory authorities to investigate the practice further.

In an ongoing process spanning between February 19, 2015 to December 9, 2019, the AER has developed monitoring and reporting requirements that apply to all oil and natural gas producers working in certain areas where the likelihood of an earthquake is higher, and implemented the requirements in *Subsurface Order Nos. 2*, *6*, and *7*. The regions with seismic protocols in place that are aimed at limiting the impact and potential of induced earthquakes from hydraulic fracturing are Fox Creek, Red Deer, and Brazeau (the "**Seismic Protocol Regions**"). Oil and natural gas producers in each of the Seismic Protocol Regions are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude. The thresholds vary among the Seismic Protocol Regions, and trigger a sliding scale of obligations from the oil or natural gas producers operating there. The obligations range from no action required, to informing the AER and invoking an approved response plan, to ceasing operations and informing the AER. The AER has the discretion to suspend oil or natural gas producers' operations while it conducts investigations following a seismic event, and only when the AER has assessed ongoing risk of earthquakes in a specific area and/or required the oil or natural gas producer to update its response plan, can operations resume. The AER may extend these requirements to other areas of Alberta if necessary, subject to the results of the AER's ongoing province-wide monitoring.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") impacts conventional crude oil and natural gas producers, shale gas producers and other operators of crude oil and natural gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission (the "**BC Commission**") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for crude oil and natural gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The OGAA requires the BC Commission to consider these environmental objectives in deciding whether or not to authorize a crude oil or natural gas activity. In addition, although not an exclusively environmental statute, the *Petroleum and Natural Gas Act*, in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

Beginning in 2015, the British Columbia Government has introduced a regime to monitor and manage the risk of seismicity induced by the oil and natural gas industry, particularly in northern British Columbia, where hydraulic fracturing is used to access natural gas plays. The *Drilling and Production Regulation*, as amended in June 2015 requires and oil and gas producer to suspend its operations if they trigger an earthquake with a magnitude on the Richter scale of 4.0 or greater, and to implement mitigation measures approved by the BC Commission before resuming production. In June 2016, the BC Commission amended the permitting process to require all natural gas producers to conduct ground monitoring, and to submit a ground monitoring report within 30 days of completing hydraulic fracturing operations.

In May 2018, the BC Commission issued a Special Project Order under section 75 of the OGAA, which designated the Kiskatinaw Seismic Monitoring and Mitigation Area, spanning between Fort St. John and Dawson Creek (the "**Kiskatinaw Area**"). Permit holders in the Kiskatinaw Area are subject to additional requirements before they can conduct hydraulic fracturing operations, including developing a seismic monitoring and mitigation plan that is approved by the BC Commission, and notifying the BC Commission and local residents about planned hydraulic fracturing requirements. During active hydraulic fracturing operations, permit holders are required to deploy an accelerometer, have access to real-time seismicity readings and report such readings to the BC Commission on demand. If a seismic event occurs, permit holders are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude and triggers a sliding scale of obligations from permit holders. The obligations range from reporting the earthquake and developing an approved protocol for subsequent earthquakes, to initiating such protocols, to suspending operations until permitted to resume by the BC Commission**.** The BC Commission monitors Natural Resources Canada's reporting of seismicity across the province, and has installed additional seismograph stations in northeast British Columbia. Future earthquakes outside of the Kiskatinaw Area may trigger the introduction of similar requirements elsewhere in the province.

The British Columbia Government passed *Bill 51 – 2018: Environmental Assessment Act in* late 2018, which will replace the environmental assessment regime that has been in place since 2002. The updated *Environmental Assessment Act* came into force on December 16, 2019. The amendments will subject proposed projects to an enhanced environmental review process similar in substance to the federal environmental assessment process. The new environmental assessment process aims to enhance Indigenous engagement in the project approval process with an emphasis on consensus-building, in alignment with British Columbia's recent passage of Bill 41, which affirmed and adopted the United Nations Declaration on the Rights of Indigenous Peoples. Simultaneously with the enactment of the *Environmental Assessment Act*, the British Columbia Government enacted the accompanying *Reviewable Projects Regulation*, which sets out the projects subject to the new regime. The "project list" captures industrial, mining, energy, water management, waste disposal, transportation and other GHG intensive projects. In conducting an environmental assessment, the Environmental Assessment Office will consider the environmental, health, cultural, social and economic effects of a proposed project. However, many details of the new assessment process remain unknown, but the British Columbia Government has released a proposed timetable for the release of supplementary and informational materials through 2020.

In 2018, the British Columbia Government proposed amendments to the BC EMA that would see new heavy oil imports, whether by rail, expanded pipeline, or otherwise, managed through a discretionary permitting process (the "**Proposed Amendments**"). The Proposed Amendments would directly affect the transport of heavy oil blends across British Columbia to tidewater through the Trans Mountain Pipeline. In its unanimous decision, the *Reference Re Environmental Management Act (British Columbia)* delivered May 24, 2019; the British Columbia

Court of Appeal held that the Proposed Amendments are unconstitutional. The Supreme Court of Canada heard British Columbia's appeal on January 16, 2020, and found that, constitutionally, the British Columbia Government does not have the jurisdiction to make the Proposed Amendments. The Supreme Court of Canada unanimously dismissed the appeal and adopted the reasons of the British Columbia Court of Appeal. On January 29, 2020, the Government of British Columbia acknowledged that Canada's highest court has ruled in support of the Trans Mountain Pipeline expansion proceeding, and indicated that the Government of British Columbia would not initiate further challenges against the Trans Mountain Pipeline.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources is the primary regulator of crude oil and natural gas activities in the province. *The Oil and Gas Conservation Act* (the "**SKOGCA**") is the act governing the regulation of resource development operations in the province, along with *The Oil and Gas Conservation Regulations, 2012* (the "**OGCR**") and *The Petroleum Registry and Electronic Documents Regulations* (the "**Registry Regulations**"). The aim of the SKOGCA, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. The Government of Saskatchewan has implemented a number of operational requirements, including an increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural requirements including those related to Saskatchewan's participation as partner in the Petrinex Database.

Liability Management Rating Program

Alberta

The AER administers the licensee Liability Management Rating Program (the "**AB LMR Program**"). The AB LMR Program is a liability management program governing most conventional upstream crude oil and natural gas wells, facilities and pipelines. It consists of three distinct programs: the Licensee Liability Rating Program (the "**AB LLR Program**"), the Oilfield Waste Liability Program (the "**AB OWL Program**") and the Large Facility Liability Management Program (the "**AB LFP**"). If a licensee's deemed liabilities in the AB LLR Program, the AB OWL Program and/or the AB LFP exceed its deemed assets in those programs, the AB LMR Program requires the licensee to provide the AER with a security deposit and may restrict the licensee's ability to transfer licences. This ratio of a licensee's assets to liabilities across the three programs is referred to as the licensee's liability management rating ("**LMR**"). Where the AER determines that a security deposit is required, the failure to post any required amounts may result in the initiation of enforcement action by the AER.

The AER previously assessed the LMR of all licensees on a monthly basis and posted the individual ratings on the AER's public website. However, in December 2019 the AER ceased posting the detailed LMR report, stating that resource and budget limitations have impacted its ability to maintain and administer the AB LMR Program. Licensees can continue to access their individual LMR calculations through the AER's Digital Data Submission System. The AER is currently reviewing the AB LMR Program as it no longer considers the LMR value alone to be a good indicator of a company's financial health. It is unclear if, or when, any changes will be made to the current regulatory framework. Any changes to the AB LMR Program may affect the Company's ability to obtain or transfer licenses.

Complementing the AB LMR Program, Alberta's **OGCA** establishes an orphan fund (the "**Orphan Fund**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program and the AB OWL Program if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. Licensees in the AB LLR Program and AB OWL Program, including the Company, fund the Orphan Fund through a levy administered by the AER. A separate orphan levy applies to persons holding licences subject to the AB LFP. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

On January 31, 2019, the Supreme Court of Canada overturned the lower courts' decisions in *Redwater Energy Corporation (Re)* ("**Redwater**"), holding that there is no operational conflict between the abandonment and reclamation provisions contained in the provincial OGCA, the liability management regime administered by the AER and the federal bankruptcy and insolvency regime. As a result, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets of a bankrupt licensee that have reached the end of their productive lives and represent a liability and deal with the company’s valuable assets for the benefit of the company's creditors, without first satisfying abandonment and reclamation obligations.

In response to the lower courts' decisions in Redwater, the AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs. In Response to Redwater's trajectory through the Courts, the AER introduced amendments to its liability management framework. The AER amended its *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which deals with licensee eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information, including whether any director and officer was a director or officer of an energy company that has been subject to insolvency proceedings in the last five years. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all transfers are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LMR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that it can meet its abandonment and reclamation obligations. The AER may make further rule changes at any time. The Supreme Court of Canada's Redwater decision alleviates some of the concerns that the AER's rule changes were intended to address, however the AER has indicated it is in the process of reviewing the current framework.

The AER has also implemented the Inactive Well Compliance Program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells* ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission System. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota. From April 1, 2016 to April 1, 2017, this number fell from 17,470 to 12,375 noncompliant wells, with 81% of licensees operating in the province having met their annual quota. The IWCP will complete its fifth year on March 31, 2020 but the AER has not released subsequent annual reports on compliance levels since 2017.

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure, the AER announced a voluntary area-based closure ("**ABC**") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations though industry collaboration and economies of scale. Participants seeking the program incentives must commit to an inactive liability reduction target to be met through closure work of inactive assets.

British Columbia

Similar to Alberta, the BC Commission oversees a Liability Management Rating Program (the "**BC LMR Program**"), which is designed to manage public liability exposure related to crude oil and natural gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the BC LMR Program, the BC Commission determines the required security deposits for permit holders under the OGAA. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets (i.e., an LMR of below a ratio of 1.0) will be considered at-risk and reviewed for a security deposit. Permit holders that fail to comply with security deposit requirements are deemed non-compliant under the OGAA and enter the compliance and enforcement framework.

As a result of certain amendments to the OGAA, on April 1, 2019 a liability-based levy paid to the Orphan Site Reclamation Fund ("**OSRF**") replaced the orphan site reclamation fund tax paid by permit holders. Similar to

Alberta's Orphan Fund, the OSRF is an industry-funded program created to address the abandonment and reclamation costs for orphan sites. Permit holders are required to pay their proportionate share of the regulated amount of the levy, calculated using each permit holder's proportionate share of the total liabilities of all permit holders required to contribute to the fund. The OGAA permits the BC Commission to impose more than one levy in a given calendar year.

Effective May 31, 2019, the *Dormancy and Shutdown Regulation* (the "**Dormancy Regulation**") establishes the first set of legally imposed timelines for the restoration of oil and natural gas wells in Western Canada. The Dormancy Regulation classifies different sites based on activity levels associated with the well(s) on each site, with a goal of ensuring that 100% of currently dormant sites are reclaimed by 2036 with additional regulated timelines for sites that become dormant between 2019 and 2023 or become dormant after 2024. A permit holder will have varying reporting, decommissioning, remediation and reclamation obligations that depend on the classification of its sites. Any permit holder that has a dormant site in its portfolio must develop and submit an annual work plan to the BC Commission, outlining its decommissioning and restoration activities for each calendar year. The permit holder must also prepare and submit a retrospective annual report within 60 days of the end of the calendar year in which it conducted the work outlined in an annual work plan.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources administrates the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to the orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when the Saskatchewan Ministry of Energy and Resources confirms there is no legally responsible or financially able party to deal with the abandonment and/or reclamation responsibilities. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets (i.e., an LLR below 1.0) to post a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month for all licensees of crude oil, natural gas and service wells and upstream crude oil and natural gas facilities. On August 19, 2016, the Saskatchewan Ministry of the Economy released a notice to all operators introducing interim measures in response to Redwater. Among other things, the Saskatchewan Ministry of the Economy announced that it considers all licence transfer applications non-routine as it does not strictly rely on the standard LLR calculation in evaluating deposit requirements. In addition to increased security deposit requirements, the Saskatchewan Ministry of the Economy at that time announced in 2016 that it may incorporate additional conditions with licence transfer approvals..

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the future of the crude oil and natural gas industry in Canada.

The impacts of federal or provincial climate change and environmental laws and regulations are uncertain. It is currently not possible to predict the extent of future requirements. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on the Company's operations and cash flow.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries, including Canada, signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. As of December 23, 2019, 187 of the 197 parties to the convention have ratified the Paris Agreement. In December 2019, the United Nations annual Conference of the Parties took place in Madrid, Spain. The Conference concluded with the attendees delaying decisions about a prospective carbon market and emissions cuts until the next climate conference in Glasgow in 2020. However, the European Union reached an agreement about "The European Green New Deal" that aims to lower emissions to zero by 2050.

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030. Further, on December 9, 2016, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"). The Framework provided for a carbon-pricing strategy, with a carbon tax starting at $10/tonne in 2018, increasing annually until it reaches $50/tonne in 2022. This system applies in provinces and territories that request it and in those that do not have a carbon pricing system in place that meets the federal standards. On June 21, 2018, the federal government enacted the *Greenhouse Gas Pollution Pricing Act* (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an emissions trading system for large industry and a regulatory fuel charge imposing an initial price of $20/tonne of GHG emissions. Under current federal plans, this price will escalate by $10 per year until it reaches a price of $50/tonne in 2022. Starting April 1, 2020, the minimum price permissible under the GGPPA is $30/tonne of GHG emissions.

Six provinces and territories have introduced carbon-pricing systems that meet federal requirements: British Columbia, Quebec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador, and the Northwest Territories. The federal fuel charge regime took effect in Saskatchewan, Manitoba, Ontario, and New Brunswick on April 1, 2019 and in the Yukon and Nunavut on July 1, 2019. The federal fuel charge regime took effect in Alberta on January 1, 2020.

Alberta, Saskatchewan, and Ontario have referred the constitutionality of the GGPPA to their respective Courts of Appeal. In both the Saskatchewan and Ontario references the appellate Courts ruled in favour of the constitutionality of the GGPPA. The Attorneys General of Saskatchewan and Ontario have appealed these decisions to the Supreme Court of Canada and the Court is set to hear the appeals in March 2020. On February 24, 2020, the Alberta Court of Appeal determined that the GGPPA is unconstitutional. It is unclear whether the Alberta reference will be appealed and heard with the Saskatchewan and Ontario appeals or, relatedly, whether those scheduled hearings will be delayed as a result. However, each of Saskatchewan, Ontario and Alberta will participate in the scheduled hearings, along with the Attorneys General of Quebec, New Brunswick, Manitoba and British Columbia and various other interested parties.

On April 26, 2018, the federal government passed the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the crude oil and natural gas sector, and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

In October 2018, the federal government announced a pricing scheme as an alternative for large electricity generators so as to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation capacity.

Finally, the federal government has also enacted the *Multi-Sector Air Pollutants Regulation* under the authority of the *Canadian Environmental Protection Act, 1999*, which seeks to regulate certain industrial facilities and equipment types, including boilers and heaters used in the upstream oil and natural gas industry, to limit the emission of air pollutants such as nitrogen oxides and sulphur dioxide.

Alberta

On November 22, 2015, the Government of Alberta introduced a Climate Leadership Plan (the "**CLP**"). Under this strategy, the *Climate Leadership Act* (the "**CLA**") came into force on January 1, 2017 and established a fuel charge intended to first outstrip and subsequently keep pace with the federal price. On December 14, 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, excluding some attributable to upgraders, the electric energy portion of cogeneration and other prescribed emissions.

In June 2019, the Government of Alberta pivoted in its implementation of the CLP and repealed the CLA. The Carbon Competitiveness Incentives Regime ("**CCIR**") remained in place. As a result, the federally imposed fuel charge took effect in Alberta on January 1, 2020, at a rate of $20/tonne. In accordance with the GGPPA, this will increase to $30/tonne on April 1, 2020. However, on December 4, 2019, the federal government approved Alberta's proposed *Technology Innovation and Emissions Reduction* ("**TIER**") regulation intended to replace the CCIR, so the regulation of emissions from heavy industry remains subject to provincial regulation, while the federal fuel charge still applies. The TIER regulation came into effect on January 1, 2020.

The TIER regulation operates differently than the former facility-based CCIR, and instead applies industry-wide to emitters that emit more than 100,000 tonnes of CO_2e per year in 2016 or any subsequent year. The 2020 target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark (which is, generally, its average emissions intensity during the period from 2013 to 2015), with a further 1% reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard, which measures against the emissions produced by the cleanest natural gas-fired generation system. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available to ensure that the cost of ongoing compliance takes this into account. As with the former CCIR, the TIER regulation targets emissions intensity rather than total emissions. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program despite the fact that they do not meet the 100,000 tonne threshold. A facility can opt-in to TIER regulation if it competes directly against another TIER-regulated facility or if it has annual CO_2e emissions that exceed 10,000 tonnes per year and belongs to an emissions-intensive or trade exposed sector with international competition. In addition, the owner of two or more "conventional oil and gas facilities" may apply to have those facilities regulated under the TIER regulation. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

The Government of Alberta previously signaled its intention through the CLP to implement regulations that would lower annual methane emissions by 45% by 2025. Pursuant to this goal, the Government of Alberta enacted the *Methane Emission Reduction Regulation* (the "**Alberta Methane Regulations**") on January 1, 2020, and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*. The release of Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for Oil and Gas Operations* that took effect in December 2018. Together, these new Directives represent Alberta's first step toward achieving its 2025 goal, as outlined in the Alberta Methane Regulations; however, the Government of Alberta and the federal government have not yet reached an equivalency agreement with respect to the Alberta Methane Regulations and the Federal Methane Regulations.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion through 2025 to fund two commercial-scale carbon capture and storage projects. Both projects will help reduce the CO_2 emissions from the oil sands and fertilizer sectors, and reduce GHG emissions by 2.76 million megatonnes per year. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

British Columbia

On August 19, 2016, the Government of British Columbia launched its Climate Leadership Plan, which aims to reduce British Columbia's net annual emissions by up to 25 million tonnes below current forecasts by 2050 and recommit the province to achieving its target of reducing emissions by 80% below 2007 levels by 2050.

British Columbia was also the first Canadian province to implement a revenue-neutral carbon tax. In 2012, the carbon tax was frozen at $30/tonne. However, the Government raised the carbon tax to $35/tonne in April 2018, and subsequently raised it to $40/tonne on April 1, 2019. The Government of British Columbia intends to continue raising its carbon tax in $5 increments until it reaches $50/tonne in 2021.

On January 1, 2016, the Greenhouse Gas Industrial Reporting and Control Act (the "**GGIRCA**") came into effect, which streamlined the regulatory process for large emitting facilities. The GGIRCA sets out various performance standards for different industrial sectors and provides for emissions offsets through the purchase of credits or through emission offsetting projects.

On December 5, 2018, the Government of British Columbia announced an updated clean energy plan, "**CleanBC**", which seeks to ensure that British Columbia achieves 75% of its GHG emissions reduction target by 2030. The CleanBC plan includes a number of strategies targeting the industrial, transportation construction, and waste sectors of the British Columbia economy. Key initiatives include: i) increasing the generation of electricity from clean and renewable energy sources; ii) imposing a 15% renewable content requirement in natural gas by 2030; iii) requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20% by 2030; iv) investing in the electrification of crude oil and natural gas production; v) reducing 45% of methane emissions associated with natural gas production; and vi) incentivizing the adoption of zero-emissions vehicles. The 2019 provincial budget provided $902 million over three years to support CleanBC, including electric vehicle rebates, incentives for making homes and businesses more energy efficient, and an enhanced climate action tax credit. On January 16, 2019, the BC Commission announced a series of amendments to the British Columbia *Drilling and Production Regulation* that will require facility and well permit holders to, among other things, reduce natural gas leaks and curb monthly natural gas emissions from their equipment and operations. These new rules came into effect on January 1, 2020.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced the *Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. On October 18, 2016, the Government of Saskatchewan released a White Paper on Climate Change, resisting a carbon tax and committing to an approach that focuses on technological innovation and adaptation. Subsequently, the Government released *Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy* outlining its strategy to reduce GHG emissions by 12 million tonnes by 2030.

The MRGGA, which is partially compliant with the federal emissions trading system, was partially proclaimed into force on January 1, 2018, establishes a framework to reduce GHG emissions by 20% of 2006 levels by 2020. An amended version of the MRGGA was proclaimed in full in December 18, 2018, establishing the framework of an output-based emissions management framework.

Under the MRGGA, facilities that have annual GHG emissions in excess of 50,000 tonnes are regulated to meet the province's reduction targets. The following regulations were enacted throughout 2018: *The Management and Reduction of Greenhouse Gases (General and Electricity Producer) Regulations*, the *Management and Reduction of Greenhouse Gases (Reporting and General) Regulations*, and *The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations*. These Regulations establish reporting requirements and impose various emissions limits for those emitters that fall within the program. On January 1, 2019, *The Oil and Gas Emissions Management Regulations* (the "**Saskatchewan O&G Emissions Regulations**") came into effect. The Saskatchewan O&G Emissions Regulations apply to licensees of oil facilities that may generate more than 50,000 tonnes of CO_2e per year, obliging each licensee to propose an emissions reduction plan in accordance with an annual emissions limit with the goal of achieving annual emissions reductions of 40 to 45% by 2025. The Saskatchewan O&G Emissions Regulations aim to achieve 4.5 million tonne CO_2e reduction in emissions by 2025, and a total reduction of 38.2 million tonnes CO_2e between 2020 and 2030.

On April 10, 2019, Saskatchewan produced the first annual report on climate resilience. The report measures the Province's progress on goals set out under *Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy*. Among these goals is the aim of increasing the role of renewable energy in the provincial energy mix to 50% by 2030.

On October 1, 2019, *Bill 147 – An Act to amend The Oil and Gas Conservation Act*, was proclaimed into force that, in part, amends the SKOGCA to the extent necessary to bring it into alignment with the Saskatchewan O&G Emissions Regulations discussed above.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Company's other public filings before making an investment decision. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with the Company's business and the oil and natural gas business generally.

Exploration, Development and Production Risks

The Company's future performance may be affected by the financial, operational, environmental and safety risks associated with the exploration, development and production of oil and natural gas

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, the Company's existing reserves, and the production from them, will decline over time as the Company produces from such reserves. A future increase in the Company's reserves will depend on both the ability of the Company to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Company will be able to continue to find satisfactory properties to acquire or participate in. Moreover, management of the Company may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that the Company will discover or acquire further commercial quantities of oil and natural gas.

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

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, shut-ins of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision, effective maintenance operations and the development of enhanced oil recovery technologies can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment and cause personal injury or threaten wildlife. Particularly, the Company may explore for and produce sour gas in certain areas. An unintentional leak of sour 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.

Oil and natural gas production operations are also subject to geological and seismic risks, 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.

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

Weakness in the Oil and Natural Gas Industry

Weakness and volatility in the market conditions for the oil and natural gas industry may affect the value of the Company's reserves, restrict its cash flow and ability to access capital to fund the development of it properties

Market events and conditions, including global excess oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**"), sanctions against Iran and Venezuela, slowing growth in China and emerging economies, weakening global relationships, conflict between the U.S. and Iran, isolationist and punitive trade policies, U.S. shale production, sovereign debt levels and political upheavals in various countries including growing anti-fossil fuel sentiment, have caused significant volatility in commodity prices. See "*Risk Factors – Political Uncertainty*". These events and conditions have caused a significant reduction in the valuation of oil and natural gas companies and a decrease in confidence in the oil and natural gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. See "*Risk Factors –Royalties and Incentives", "Risk Factors – Regulatory Authorities and Environmental Regulation*" and "*Risk Factors – Climate Change Regulation*". In addition, the difficulties encountered by midstream proponents to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and natural gas industry in Western Canada has led to additional downward price pressure on oil and natural gas produced in Western Canada. The resulting price differential between Western Canadian Select crude oil, and Brent and West Texas Intermediate crude oil has created uncertainty and reduced confidence in the oil and natural gas industry in Western Canada. See "*Industry Conditions – Transportation Constraints and Market Access*".

Lower commodity prices may also affect the volume and value of the Company's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices restrict the Company's cash flow resulting in less funds from operations being available to fund the Company's capital expenditure budget. Consequently, the Company may not be able to replace its production with additional reserves and both the Company's production and reserves could be reduced on a year-over-year basis. See "*Reserves Estimates*" in these Risk Factors. Any decrease in the value of the Company's reserves may reduce the borrowing base under its credit facilities, which, depending on the level of the Company's indebtedness, could result in the Company having to repay a portion of its indebtedness. See "*Credit Facilities*" in these Risk Factors. In addition to possibly resulting in a decrease in the value of the Company's economically recoverable reserves, lower commodity prices may also result in a decrease in the value of the Company's infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of the Company's oil and natural gas assets on its balance sheet and the recognition of an impairment charge in its income statement. Given the current market conditions and the lack of confidence in the Canadian oil and natural gas industry, the Company may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive terms. See "*Additional Funding Requirements*" in these Risk Factors.

Prices, Markets and Marketing

Various factors may adversely impact the marketability of oil and natural gas, affecting net production revenue, production volumes and development and exploration activities

The Company's ability to market its oil and natural gas may depend upon its ability to acquire capacity in pipelines that deliver oil, NGLs and natural gas to commercial markets or contract for the delivery of crude oil and

NGLs by rail. Numerous factors beyond the Company's control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by the Company, including:

- deliverability uncertainties related to the distance the Company's reserves are from pipelines, railway lines and processing and storage facilities;
- operational problems affecting pipelines, railway lines and processing and storage facilities; and
- government regulation relating to prices, taxes, royalties, land tenure, allowable production and the export of oil and natural gas.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, conflicts in the Middle East and ongoing credit and liquidity concerns. Prices for oil and natural gas are also subject to the availability of foreign markets and the Company's ability to access such markets. A 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 because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Company's reserves. The Company might also elect not to produce from certain wells at lower prices. Any substantial and extended decline in the price of oil and natural 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.

See "*Industry Conditions – Transportation Constraints and Marketing*" and "*Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry*".

Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for, and project the return on, acquisitions and development and exploitation projects.

Alternatives to and Changing Demand for Petroleum Products

Changes to the demand for oil and natural gas products and the rise of petroleum alternatives may negatively affect the Company's financial condition, results of operations and cash flow

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation devices could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar effect on the demand for oil and natural gas products. The Company cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Company's business, financial condition, results of operations and cash flow by decreasing the Company's profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Reserves Estimates

The Company's estimated reserves are based on numerous factors and assumptions which may prove incorrect and which may affect the Company

There are numerous uncertainties inherent in estimating reserves, and the future cash flows attributed to such reserves. The reserves and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves (including the breakdown of reserves by product type) and the future net cash flows from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas are often 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 natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Company intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and therefore does not reflect changes in the Company's reserves since that date.

Gathering and Processing Facilities, Pipeline Systems and Rail

Lack of capacity and/or regulatory constraints on gathering and processing facilities, pipeline systems and railway lines may have a negative impact on the Company's ability to produce and sell its oil and natural gas

The Company delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that the Company can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. Notwithstanding the Alberta government's plans to purchase up to 7,000 rail cars and the implementation of production curtailment in Alberta, the ongoing lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines could result in the Company's inability to realize the full economic potential of its production or in a reduction of the price offered for the Company's production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. However, in early 2020, the Supreme Court of Canada and the Federal Court of Appeal both dismissed challenges to Cabinet’s approval of the Trans Mountain Pipeline expansion and construction on the pipeline expansion is underway. See "*Industry Conditions – Transportation*

Constraints and Market Access ". In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Company's production, operations and financial results. As a result, producers are increasingly turning to rail lines as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm the Company's business and, in turn, the Company's financial condition, operations and cash flows. Announcements and actions taken by the federal government and the provincial governments of British Columbia, Alberta and Quebec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. In addition, while the federal government introduced Bill C-69 to overhaul the existing environmental assessment process and replace the NEB with a new regulatory agency, the impact of the new proposed regulatory scheme on proponents and the timing for receipt of approvals of major projects remains unclear.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the *Safe and Accountable Rail Act* which increased insurance obligations on the shipment of crude oil by rail and imposed a per tonne levy of $1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway transportation to alleviate pipeline constraints and adds additional costs to the transportation of crude oil by rail. On July 13, 2016, the Minister of Transport (Canada) issued Protective Direction No. 38, which directed that the shipping of crude oil on DOT-111 tank cars end by November 1, 2016. Tank cars entering Canada from the United States will be monitored to ensure they are compliant with Protective Direction No. 38.

A portion of the Company's production may, from time to time, be processed through facilities owned by third parties and over which the Company does not have control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse effect on the Company's ability to process its production and deliver the same to market. Midstream and pipeline companies may take actions to maximize their return on investment which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

Substantial Capital Requirements

The Company's access to capital may be limited or restricted as a result of factors related and unrelated to it, impacting its ability to conduct future operations and acquire and develop reserves

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

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

Further, if the Company's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. The conditions in, or affecting, the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies, including the Company, to access additional financing and/or the cost thereof. 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 Company may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. 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 may require additional financing from time to time to fund the acquisition, exploration and development of properties and its ability to obtain such financing in a timely fashion and on acceptable terms may be negatively impacted by the current economic and global market volatility

The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and, from time to time, the Company may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain 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. Due to the conditions in the oil and natural gas industry and/or global economic and political volatility, the Company may, from time to time, have restricted access to capital and increased borrowing costs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access, or the cost of, additional financing.

As a result of global economic and political volatility, the Company may, from time to time, have restricted access to capital and increased borrowing costs. Failure to obtain suitable 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. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Company's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Company's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing shareholders. Failure to obtain any financing necessary for the Company's capital expenditure plans may result in a delay in development or production on the Company's properties.

Credit Facility Arrangements

Failing to comply with covenants under the Company's credit facilities could result in restricted access to capital or being required to repay all amounts owing thereunder

The Company currently has a number of covenant-based credit facilities which include certain financial ratio tests. These financial ratio tests, from time to time either affect the availability, or price, of additional funding and in the event that the Company does not comply with these covenants, the Company's access to capital could be restricted or repayment could be required. Events beyond the Company's control may contribute to the failure of the Company to comply with such covenants. A failure to comply with covenants could result in default under the Company's credit facility, which could result in the Company being required to repay amounts owing thereunder. The acceleration of the Company's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Company's credit facility may impose operating and financial restrictions on the Company that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Company's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

If the Company's lenders require repayment of all or a portion of the amounts outstanding under its credit facilities for any reason, including for a default of a covenant, there is no certainty that the Company would be in a position to make such repayment. Even if the Company is able to obtain new financing in order to make any required repayment under its credit facilities, it may not be on commercially reasonable terms or terms that are acceptable to the Company. If the Company is unable to repay amounts owing under its credit facilities, the lenders under the credit facilities could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

Regulatory

Modification to current, or implementation of additional, regulations may reduce the demand for oil and natural gas and/or increase the Company's costs and/or delay planned operations

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing, transportation and infrastructure). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties, the exportation of oil and natural gas and infrastructure projects. Amendments to these controls and regulations may occur 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 crude oil and natural gas and increase the Company's costs, either of which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Further, the ongoing third party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the oil and natural gas industry. Recently, the federal government and certain provincial governments have taken steps to initiate protocols and regulations to limit the release of methane from oil and natural gas operations. Such draft regulations and protocols may require additional expenditures or otherwise negatively impact the Company's operations, which may affect the Company's profitability. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulations*". Also, in response to widening pricing differentials, the Alberta government implemented production curtailment. See "*Industry Conditions – Curtailment*".

In order to conduct oil and natural gas operations, the Company will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the municipal, provincial and federal level. There can be no assurance that the Company will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition, certain federal legislation such as the *Competition Act* and the *Investment Canada Act* could negatively affect the Company's business, financial condition and the market value of its Common Shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity.

Political Uncertainty

The Company's business may be adversely affected by recent political and social events and decisions made in Canada, the United States, Europe and elsewhere

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the American administration has withdrawn the United States from the Trans-Pacific Partnership and the United States Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. In addition, NAFTA has been renegotiated and on November 30, 2018, Canada, the U.S. and Mexico signed the USMCA which will replace NAFTA once ratified by the three signatory countries. The USMCA was ratified by Mexico's Senate in June 2019 and by the United States' Senate in January 2020. In January 2020, the Canadian Parliament tabled Bill C-4 which, once proclaimed into force, will ratify the USMCA. The USMCA is expected to fully replace NAFTA two months after Bill C-4 comes into force. See "*Industry Conditions - The North American Trade Agreement and Other Trade Agreements*". The U.S. administration has also taken action with respect to reduction of regulation, which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other actions the U.S. administration will implement, and if implemented, how these actions may impact Canada and in particular the oil and natural gas industry. Any actions taken by the current U.S. administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies, including the Company.

In addition to the political disruption in the United States, the impact of the United Kingdom's exit from the European Union remains to be determined. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. Conflict and political uncertainty also continues to progress in the Middle East. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement, it could have an adverse effect on the Company's ability to market its products internationally, increase costs for goods and services required for the Company's operations, reduce access to skilled labour and negatively impact the Company's business, operations, financial conditions and the market value of the common shares.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy. Alberta elected a new government in 2019 that is supportive of the Trans Mountain Pipeline expansion project. Though the Supreme Court of Canada unanimously rejected the government of British Columbia's proposed regulation of the transport of heavy oil products into and through British Columbia in January 2020, tensions remain high between provincial and federal governments. Continued uncertainty and delays have led to decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdiction where the Company is active. See "*Industry Conditions – Transportation Constraints and Market Access*" and "*Industry Conditions – Regulatory Authorities and Environmental Regulation – British Columbia*".

The federal Government was re-elected in 2019, but in a minority position. The ability of the minority federal government to pass legislation will be subject to whether it is able to come to agreement with, and garner the support of, the other elected parties, most of whom are opposed to the development of the oil and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Lack of political consensus, at both the federal and provincial level, continues to create regulatory uncertainty, the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes, curtailment of crude oil production and transportation and export capacity, and may affect the business of participants in the oil and natural gas industry. See "*Industry Conditions – Climate Change Regulation"*, "*Industry Conditions – Transportation Constraints and Market Access*", "*Industry Conditions – Curtailment*" and "*Industry Conditions – The North American Free Trade Agreement and other Trade Agreements*".

The oil and natural gas industry has become an increasingly politically polarizing topic in Canada, which has resulted in a rise in civil disobedience surrounding oil and natural gas development—particularly with respect to infrastructure projects. Protests, blockades and demonstrations have the potential to delay and disrupt the Company's activities. See "*Industry Conditions – Transportation Constraints and Market Access – Natural Gas*".

Project Risks

The success of the Company's operations may be negatively impacted by factors outside of its control resulting in operational delays, and cost overruns and marketing challenges

The Company manages a variety of small and large projects in the conduct of its business. Project interruptions may delay expected revenues from operations. Significant project cost overruns 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 availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods or the Company's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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

Competition

The Company competes with other oil and natural gas companies, some of which have greater financial and operational resources

The petroleum industry is competitive in all of its phases. The Company competes with numerous other entities in the exploration, development, production and 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. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than 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, process, and reliability of delivery and storage.

Market Price

The trading price of the Common Shares may be adversely affected by factors related and unrelated to the oil and natural gas industry

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Company's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, or current perceptions of the oil and natural gas market. In recent years, the volatility of commodities has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, in certain jurisdictions, institutions, including government sponsored entities, have determined to decrease their ownership in oil and natural gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities. Similarly, the market price of the Common Shares of the Company could be subject to significant fluctuations in response to variations in the Company's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares of the Company will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The anticipated benefits of acquisitions may not be achieved and the Company may dispose of non-core assets for less than their carrying value on the financial statements as a result of weak market conditions

The Company considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the 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 businesses and assets may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided by third parties and the resources required to provide such services. In this regard, non-core assets may be periodically disposed of so 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 may realize less on disposition than their carrying value on the financial statements of the Company.

Operational Dependence

The successful operation of a portion of the Company's properties is dependent on third parties

Other companies operate some of the assets in which the Company has an interest. 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 depends upon a number of factors that may be outside of the Company's control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which the Company has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which the Company has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations the Company may be required to satisfy such obligations and to seek reimbursement from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the Company potentially becoming subject to additional liabilities relating to such assets and the Company having difficulty collecting revenue due from such operators or recovering amounts owing to the Company from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse affect on the Company's financial and operational results. See "*Industry Conditions – Liability Management Rating Program*".

Reliance on Royalty Payors

A portion of the Company's revenues from royalty payors and certain of its operations are dependent on the financial and operational capacity of third-party working interest owners to develop and produce from the Company's properties, over which it has limited influence.

The Company relies on other companies drilling and producing from lands in which the Company has a royalty interest. The Company has very limited ability to exercise influence over the decision of companies to drill and produce from such lands. The Company's return on lands in which it has a royalty interest depends upon a number of factors that may be outside of the Company's control, including, but not limited to, the capital expenditure budgets and financial resources of the operators who have a working interest in such lands, the ability to efficiently produce the resources from such lands and commodity prices.

In addition, due to unstable commodity prices, many companies, including companies that may have a working interest in the lands in which the Company has a royalty interest, may be in financial difficulty, which could affect their ability to fund and pursue capital expenditures on such lands. Furthermore, weak commodity prices and/or curtailment of the production of crude oil mandated by the Government of Alberta may result in companies choosing to defer capital spending or shutting-in existing production. See "*Industry Conditions –*

Curtailment". Any reduction in the drilling and production from lands in which the Company has a royalty interest will negatively affect the Company's cash flows and financial results.

Financial difficulty of companies who have lands in which the Company has a royalty interest may affect the Company's ability to collect royalty payments, especially if such companies go bankrupt, become insolvent, or make a proposal or institute any proceedings relating to bankruptcy or insolvency.

Cost of New Technologies

The Company's ability to successfully implement new technologies into its operations in a timely and efficient manner will affect its ability to compete

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

Royalty Regimes

Changes to royalty regimes may negatively impact the Company's cash flows

There can be no assurance that the governments in the jurisdictions in which the Company has assets will not adopt new royalty regimes, or modify the existing royalty regimes, which may have an impact on the economics of the Company's projects. An increase in royalties would reduce the Company's earnings and could make future capital investments, or the Company's operations, less economic. See "*Industry Conditions - Royalties and Incentives*".

Hydraulic Fracturing

Implementation of new regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes, adversely affecting the Company's financial position

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the Company's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Company is ultimately able to produce from its reserves.

Alberta

Minor earthquakes are common in certain parts of Alberta, and are generally clustered around the municipalities of Cardston, Fox Creek, Rocky Mountain House, Brazeau and Red Deer. Since 2015, the AER introduced seismic protocols for hydraulic fracturing operators in the Fox Creek, Brazeau and Red Deer areas. These requirements include, among others, an assessment of the potential for seismicity prior to conducting operations, the implementation of a response plan to address potential seismic events, and the suspension of operations if a seismic event above a particular threshold occurs. These requirements remain in effect as long as the AER deems them necessary. Further, the AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary. In March 2018 and March 2019, two earthquakes felt in Red Deer and Sylvan Lake were characterized as seismic activity induced by hydraulic fracturing. In March 2019, the AER suspended operations of an oil and natural gas company in the area where the earthquake occurred, pending further investigation. In May 2019, the suspended oil and natural gas company was able to resume operations with a risk assessment plan in place that was approved by the AER. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Alberta*".

British Columbia

Due to seismic activity recorded in the Kiskatinaw Seismic Monitoring and Mitigation area (the "**Kiskatinaw Area**"), in May 2018, the BC Commission issued special notification and monitoring requirements for hydraulic fracturing operators in the Kiskatinaw Area. These requirements include, among others, the submission of a seismic monitoring and mitigation plan prior to conducting operations, pre-operation notification to both residents and the BC Commission and the suspension of operations if a seismic event above a 3.0 magnitude occurs. On November 29, 2018, hydraulic fracturing operations of a natural gas producer in the Montney area in British Columbia were suspended after a series of three seismic events, ranging from 3.4 to 4.5 in magnitude, were linked to hydraulic fracturing by the BC Commission. Though the BC Commission allowed the natural gas producer to resume operations in the Montney area on October 21, 2019, this suspension demonstrates the BC Commission's willingness to enforce its enhanced regulatory requirements. The same natural gas producer was also suspended from using a wastewater disposal well in 2019 due to seismicity attributed to the use of that well, demonstrating that the BC Commission's monitoring and oversight of seismic risk is not limited to hydraulic fracturing.

In 2018, the Government of British Columbia commissioned an independent scientific review panel to analyze hydraulic fracturing in the province and determine, among other things, how British Columbia's regulatory framework can be improved to better manage safety and environmental risks resulting from hydraulic fracturing operations. The panel's recommendations included directing the Government of British Columbia to consider classifying hydraulic fracturing wastewater as hazardous waste, certain best practices for producers conducting hydraulic fracturing and increased water and seismicity monitoring by the BC Commission in northeastern British Columbia. The implementation of new regulations or modification of existing regulations, in response to the panel's findings, may adversely affect the Company's business operation, financial condition, results of operations and prospects.

See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – British Columbia*".

The Government of British Columbia has come under increased scrutiny for its enforcement of environmental assessment, safety and licensing requirements for dams companies have built in association with their hydraulic fracturing operations. Under the *Water Sustainability Act*, dams require a water licence. For dams over a certain size, dam-operators must comply with additional safety and reporting requirements set out in the *Dam Safety Regulation*. Larger dams are also subject to an environmental assessment and approval under the *Environmental Assessment Act*. Despite these regulatory requirements, reports have surfaced indicating that a number of unlicensed dams throughout northeastern BC have been constructed without the requisite regulatory authorization. While the BC Commission has issued compliance orders with respect to individual dams, it is uncertain how, and to what extent the relevant industry regulators will respond to this issue. The Company may face operational delays depending on the level of severity with which the overseeing regulatory authorities decide to address these unauthorized projects, particularly where the Company is not strictly complying with the current regulatory framework.

Disposal of Fluids used in Operations

Regulations regarding the disposal of fluids used in the Company's operations may increase its costs of compliance or subject it to regulatory penalties or litigation

The safe disposal of the hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the federal and provincial governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the impact of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase the Company's costs of compliance.

Environmental

Compliance with environmental regulations requires the dedication of a portion of the Company's financial and operational resources

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, the initiation and approval of new oil and natural gas projects, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and natural gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. New environmental legislation at the federal and provincial levels may increase uncertainty among oil and natural gas industry participants as the new laws are implemented, and the effects of the new rules and standards are felt in the oil and natural gas industry. See "*Industry Conditions – Exports from Canada*", "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*".

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge. Although the Company believes that it will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements 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.

Carbon Pricing Risk

Taxes on carbon emissions affect the demand for oil and natural gas, the Company's operating expenses and may impair the Company's ability to compete

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the federal government implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system currently applies in provinces and territories without their own system that meets federal standards. The federal regime is subject to a number of court challenges. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". Any taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the Company's operating expenses, each of which may have a material adverse effect on the Company's profitability and financial condition. Further, the imposition of carbon taxes puts the Company at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Liability Management

Liability management programs enacted by regulators in the western provinces may prevent or interfere with the Company's ability to acquire properties or require a substantial cash deposit with the regulator

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. Changes to the AB LMR Program administered by the AER, or other changes to the requirements of liability management programs, may result in significant increases to the Company's compliance obligations. The impact and consequences of the Supreme Court of Canada's decision in Redwater on the AER's rules and policies, lending practices in the crude oil and natural gas sector and on the nature and determination of secured lenders to take enforcement proceedings are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. In addition, the AB LMR Program may prevent or interfere with the Company's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

Climate Change

Climate change may pose varied and far ranging risks to the business and operations of the Company, both known and unknown, that may adversely affect the Company's business, financial condition, results of operations, prospects, reputation and share price

The Company's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Company to comply with GHG emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the UNFCCC and a signatory to the Paris Agreement, which was ratified in Canada on October 3, 2016, the Government of Canada pledged to cut its GHG emissions by 30 per cent from 2005 levels by 2030. One of the pertinent policies announced to date by the Government of Canada to reduce GHG emission is the planned implementation of a nation-wide price on carbon emissions. The federal carbon levy goes into effect on April 1, 2019 and will affect provinces which have not implemented their own carbon taxes, cap-and-trade systems or other plans for carbon pricing, namely Ontario, Manitoba, Saskatchewan and New Brunswick. The federal carbon levy will be at an initial rate of $20 per tonne. Provincially, the Government of Alberta has already implemented a carbon levy on almost all sources of GHG emissions, now at a rate of $30 per tonne. The implementation of the federal carbon levy is currently subject to a constitutional challenge submitted by the Province of Saskatchewan, which is supported by the Provinces of Ontario and New Brunswick. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Some of the Company's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Historically, political and legal opposition to the fossil fuel industry focused on public opinion and the regulatory process. More recently, however, there has been a movement to more directly hold governments and oil and natural gas companies responsible for climate change through climate litigation. In November 2018, ENvironment JEUnesse, a Quebec advocacy group, applied to the Quebec Superior Court to certify a class action against the Government of Canada for climate related matters. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against oil and natural gas producers for climate-related harms. See "*Non-Governmental Organizations and Eco and Eco-Terrorism Risks*" and "*Reputational Risk Associated with the Company's Operations*" in these Risk Factors. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Company's operating expenses and in the long-term could reduce the demand for oil and natural gas production, potentially resulting in a decrease in the Company's profitability and a reduction in the value of its assets or could result in asset write-offs. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*".

In addition, there has been public discussion that climate change may be associated with extreme weather conditions and increased volatility in seasonal temperatures. Extreme weather could interfere with the Company's production and increase the Company's costs. At this time, the Company is unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting its operations.

Chronic Climate Change Risks

The Company's exploration and production facilities and other operations and activities emit GHG which may require the Company to comply with federal and/or provincial greenhouse gas emissions legislation. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place to prevent climate change or mitigate its effects. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Some of the Company's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions

Climate change has been linked to long-term shifts in climate patterns, including sustained higher temperatures. As the level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns, long-term shifts in climate patterns pose the risk of exacerbating operational delays and other risks posed by seasonal weather patterns. See "*Risk Factors – Seasonality and Extreme Weather Conditions*". In addition, long-term shifts in weather patterns such as water scarcity, increased frequency of storm and fire and prolonged heat waves may, among other things, require the Company to incur greater expenditures (time and capital) to deal with the challenges posed by such changes to its premises, operations, supply chain, transport needs, and employee safety. Specifically, in the event of water shortages or sourcing issues, the Company may not be able to, or will incur greater costs to, carry out hydraulic fracturing operations.

Concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels which has influenced investors' willingness to invest in the oil and natural gas industry. Historically, political and legal opposition to the fossil fuel industry focused on public opinion and the regulatory process. More recently, however, there has been a movement to more directly hold governments and oil and natural gas companies responsible for climate change through climate litigation. In November 2018, ENvironment JEUnesse, a Quebec advocacy group, applied to the Quebec Superior Court to certify all Quebecois under 35 as a class in a proposed class action lawsuit against the Government of Canada for climate related matters. While the application was denied, the group has stated it plans to appeal. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against oil and natural gas producers for alleged climate-related harms. The Union of British Columbia Municipalities defeated the City of Victoria's motion to initiate a class action lawsuit to recover costs it claims are related to climate change.

Given the evolving nature of climate change policy and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Company's operating expenses, and, in the long-term, potentially reducing the demand for oil and natural gas production, resulting in a decrease in the Company's profitability and a reduction in the value of its assets or requiring asset impairments for financial statement purposes. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*", "*Risk Factors – Non-Governmental Organizations"*, "*Risk Factors – Reputational Risk Associated with the Company's Operations*" and "*Risk Factors – Changing Investor Sentiment*".

Acute Climate Change Risk

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict the Company's ability to access its properties, cause operational difficulties including damage to machinery and facilities. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of the Company's assets are located in locations that are proximate to forests and rivers and a wildfire and flood may lead to significant downtime and/or damage to such assets.

Moreover, extreme weather conditions may lead to disruptions in the Company's ability to transport produced oil and natural gas as well as goods and services in its supply chain.

Variations in Foreign Exchange Rates and Interest Rates

Variations in foreign exchange rates and interest rates could adversely affect the Company's financial condition

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect the Company's production revenues. Accordingly, exchange rates between Canada and the United States could affect the future value of the Company's reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the United States dollar may positively affect the price the Company receives for its oil and natural gas production, it could also result in an increase in the price for certain goods used for the Company's operations, which may have a negative impact on the Company's financial results**.**

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, resulting in a reduced amount available to fund its exploration and development activities, and if applicable, the cash available for dividends. Such an increase could also negatively impact the market price of the Common Shares of the Company.

Issuance of Debt

Increased debt levels may impair the Company's ability to borrow additional capital on a timely basis to fund opportunities as they arise

From time to time, the Company may enter into transactions to acquire assets or shares of other entities. 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 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

Hedging activities expose the Company to the risk of financial loss and counter-party risk

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, to the extent that the Company engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Company's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

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

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

Availability and Cost of Material and Equipment

Restrictions on the availability and cost of materials and equipment may impede the Company's exploration, development and operating activities

Oil and natural gas exploration, development and operating activities are dependent on the availability and cost of specialized materials and equipment (typically leased from third parties) in the areas where such activities are conducted. The availability of such material and equipment is limited. An increase in demand or cost, or a decrease in the availability of such materials and equipment may impede the Company's exploration, development and operating activities.

The Company requires a Skilled Workforce

An inability to recruit and retain a skilled workforce may negatively impact the Company

The operations and management of the Company require the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals. The loss of key members of such workforce, or a substantial portion of the workforce as a whole, could result in the failure to implement the Company's business plans. The Company competes with other companies in the oil and natural gas industry, as well as other industries, for this skilled workforce. A decline in market conditions has led increasing numbers of skilled personnel to seek employment in other industries. In addition, certain of the Company's current employees are senior and have significant institutional knowledge that must be transferred to other employees prior to their departure from the workforce. If the Company is unable to: (i) retain current employees; (ii) successfully complete effective knowledge transfers; and/or (iii) recruit new employees with the requisite knowledge and experience, the Company could be negatively impacted. In addition, the Company could experience increased costs to retain and recruit these professionals.

Title to and Right to Produce from Assets

Defects in the title or rights to produce the Company's properties may result in a financial loss

The Company's actual title to and interest in its properties, and its right to produce and sell the oil and natural gas therefrom, may vary from the Company's records. In addition, there may be valid legal challenges or legislative changes that affect the Company's title to and right to produce from its oil and natural gas properties, which could impair the Company's activities and result in a reduction of the revenue received by the Company.

If a defect exists in the chain of title or in the Company's right to produce, or a legal challenge or legislative change arises, it is possible that the Company may lose all, or a portion of, the properties to which the title defect relates and/or its right to produce from such properties. This may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Insurance

Not all risks of conducting oil and natural gas opportunities are insurable and the occurrence of an uninsurable event may have a materially adverse effect on the Company

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, blowouts, leaks of sour 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, certain 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

Global political events may adversely affect commodity prices which in turn affect the Company's cash flow

Political changes in North America and political instability in the Middle East and elsewhere may cause disruptions in the supply of oil that affects the marketability and price of oil and natural gas acquired or discovered by the Company. Conflicts, or conversely peaceful developments, arising outside of Canada, including changes in political regimes or parties in power, may have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of the Company's net production revenue.

Non-Governmental Organizations and Eco-Terrorism Risks

The Company's properties may be subject to action by non-governmental organizations or terrorist attack

The oil and natural gas exploration, development and operating activities conducted by the Company may, at times, be subject to public opposition. Such public opposition could expose the Company to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including indigenous groups, landowners, environmental interest groups (including those opposed to oil and natural gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of the federal, provincial or municipal governments, and delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses. There is no guarantee that the Company will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require the Company to incur significant and unanticipated capital and operating expenditures.

In addition, the Company's oil and natural gas properties, wells and facilities could be the subject of 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 does not have insurance to protect against the risk from terrorism.

Reputational Risk Associated with the Company's Operations

The Company relies on its reputation to continue its operations and to attract and retain investors and employees

The Company's business, operations or financial condition may be negatively impacted as a result of any negative public opinion towards the Company or as a result of any negative sentiment toward, or in respect of the Company's reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which the Company operates as well as their opposition to certain oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses and increased costs and/or cost overruns. The Company's reputation and public opinion could also be impacted by the actions and activities of other companies operating in the oil and natural gas industry, particularly other producers, over which the Company has no control. In particular, the Company's reputation could be impacted by negative publicity related to environmental damage, loss of life, injury or damage to property caused by the Company's operations, or due to opposition from special interest groups opposed to oil and natural gas development. In addition, if the Company develops a reputation of having an unsafe work site it may impact the ability of the Company to attract and retain the necessary skilled employees and consultants to operate its business. Opposition from special interest groups opposed to oil and natural gas development and the possibility of climate related litigation against governments and fossil fuel companies may impact the Company's reputation.

Reputational risk cannot be managed in isolation from other forms of risk. Credit, market, operational, insurance, regulatory and legal risks, among others, must all be managed effectively to safeguard the Company's reputation. Damage to the Company's reputation could result in negative investor sentiment towards the Company, which may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Company's securities.

Changing Investor Sentiment

Changing investor sentiment towards the oil and natural gas industry may impact the Company's access to, and cost of, capital

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, the impact of oil and natural gas operations on the environment, environmental damage relating to spills of petroleum products during transportation and indigenous rights, have affected certain investors' sentiments towards investing in the oil and natural gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they no longer are willing to fund or invest in oil and natural gas properties or companies, or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from the Board, management and employees of the Company. Failing to implement the policies and practices, as requested by institutional investors, may result in such investors reducing their investment in the Company, or not investing in the Company at all. Any reduction in the investor base interested or willing to invest in the oil and natural gas industry and more specifically, the Company, may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Company's securities 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 a decrease in the value of the Company's asset which may result in an impairment change.

Dilution

The Company may issue additional Common Shares, diluting current Shareholders

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 to Shareholders.

Management of Growth

The Company may not be able to effectively manage the growth of its business

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. If the Company is unable to deal with this growth, it may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Expiration of Licenses and Leases

The Company or its working interest partners may fail to meet the requirements of a licence or lease, causing its termination or expiry

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 amount of and frequency at which future cash dividends are paid may vary and there is no assurance that the Company will pay dividends in the future

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

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

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

Litigation

The Company may be involved in litigation in the course of its normal operations and the outcome of the litigation may adversely affect the Company and its reputation

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. Potential litigation may develop in relation to personal injuries (including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, environmental issues, including claims relating to contamination or natural resource damages and contract disputes). The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company and 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 proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse effect on the Company's financial condition.

Intellectual Property Litigation

Unauthorized use of intellectual property may cause the Company to engage in or be the subject of litigation

Due to the rapid development of oil and natural gas technology, in the normal course of the Company's operations, the Company may become involved in, named as a party to, or be the subject of, various legal proceedings in which it is alleged that the Company has infringed the intellectual property rights of others or which the Company initiates against others it believes are infringing upon its intellectual property rights. The Company's involvement in intellectual property litigation could result in significant expense, adversely affecting the development of its assets or intellectual property or diverting the efforts of its technical and management personnel, whether or not such litigation is resolved in the Company's favour. In the event of an adverse outcome as a defendant in any such litigation, the Company may, among other things, be required to: (a) pay substantial damages and/or cease the development, use, sale or importation of processes that infringe upon other patented intellectual property; (b) expend significant resources to develop or acquire non-infringing intellectual property; (c) discontinue processes incorporating infringing technology; or (d) obtain licences to the infringing intellectual property. However, the Company may not be successful in such development or acquisition or such licences may not be available on reasonable terms. Any such development, acquisition or licence could require the expenditure of substantial time and other resources and could have a material adverse effect on the Company's business and financial results.

Indigenous Claims

Indigenous claims may affect the Company

Indigenous peoples have claimed indigenous rights and title in 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. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays in the construction of infrastructure systems and facilities which could have a material adverse effect on the Company's business and financial results.

Breach of Confidentiality

Breach of confidentiality by a third party could impact the Company's competitive advantage or put it at risk of litigation

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

Income Taxes

Taxation authorities may reassess the Company's tax returns

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

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

Seasonality and Extreme Weather Conditions

Oil and natural gas operations are subject to seasonal and extreme weather conditions and the Company may experience significant operational delays as a result

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Roads bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of the Company's production if not otherwise tied-in. Certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of muskeg. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict the Company's ability to access its properties, cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions.

Third Party Credit Risk

The Company is exposed to credit risk of third party operators or partners of properties in which it has an interest

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 addition, the Company may be exposed to third party credit risk from operators of properties in which the Company has a working or royalty interest. 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, generally, and of the Company's joint venture partners may affect 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. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Company being unable to collect all or a portion of any money owing from such parties. Any of these factors could materially adversely affect the Company's financial and operational results.

Conflicts of Interest

Conflicts of interest may arise for the Company's directors and officers who are also involved with other industry participants

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

Reliance on Key Personnel

Loss of key personnel could negatively impact the Company's operations

The Company's success depends in large measure on certain key personnel. Losing the services of such key personnel could have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company does not have any key personnel insurance in effect. 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.

Information Technology Systems and Cyber-Security

Breaches of the Company's cyber-security and loss of, or access to, electronic data may adversely impact the Company's operations and financial position

The Company has become increasingly dependent upon the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure, to conduct daily operations. The Company depends on various information technology systems to estimate reserve quantities, process and record financial data, manage our land base, manage financial resources, analyze seismic information, administer our contracts with our operators and lessees and communicate with employees and third-party partners.

Further, the Company is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Company's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If the Company becomes a victim to a cyber phishing attack it could result in a loss or theft of the Company's financial resources or critical data and information, or could result in a loss of control of the Company's technological infrastructure or financial resources. The Company's employees are often the targets of such cyber phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to the Company's computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the email or request recipients to send a password or other confidential information through email or to download malware.

The Company maintains policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conducts annual cyber-security risk assessments. The Company also employs encryption protection of its confidential information, all computers and other electronic devices. Despite the Company's efforts to mitigate such cyber phishing attacks through education and training, cyber phishing activities remain a serious problem that may damage its information technology infrastructure. The Company applies technical and process controls in line with industry-accepted standards to protect its information, assets and systems, including a written incident response plan for responding to a cyber-security incident. However, these controls may not adequately prevent cyber-security breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation, and any damages sustained may not be adequately covered by the Company's current insurance coverage, or at all. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Company's business, financial condition and results of operations.

Social Media

The Company faces compliance and supervisory challenges in respect of the use of social media as a means of communicating with clients and the general public

Increasingly, social media is used as a vehicle to carry out cyber phishing attacks. Information posted on social media sites, for business or personal purposes, may be used by attackers to gain entry into the Company's systems and obtain confidential information. The Company restricts the social media access of its employees and periodically reviews, supervises, retains and maintains the ability to retrieve social media content. Despite these efforts, as social media continues to grow in influence and access to social media platforms becomes increasingly prevalent, there are significant risks that the Company may not be able to properly regulate social media use and preserve adequate records of business activities and client communications conducted through the use of social media platforms.

Expansion into New Activities

Expanding the Company's business exposes it to new risks and uncertainties

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

Forward-Looking Information

Forward-Looking Information May Prove Inaccurate

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

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

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 "C".

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 Financial Statements and the MD&A 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
NEBC	north east British Columbia
MM$	million dollars

$US or US$	United States dollars
2D..	two dimensional
3D..	three dimensional
Vol/d..	volumes per day

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 ability to achieve an appropriate level of quarterly cash dividends;
- 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 and abandonment and reclamation costs;
- 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;
- the Company's dividend policy; and
- the number of wells to be drilled and drilling rigs to be operated by the Company in 2019.

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;
- indigenous 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.

Without limitation of the foregoing, future dividend payments, if any, and the level thereof is uncertain, as the Company's dividend policy and the funds available for the payment of dividends from time to time will be dependent upon, among other things, free cash flow, financial requirements for the Company's operations and the execution of its growth strategy, fluctuations in working capital and the timing and amount of capital expenditures, debt service requirements and other factors beyond the Company's control. Further, the ability of Tourmaline to pay dividends will be subject to applicable laws (including the satisfaction of the solvency test contained in applicable corporate legislation) and contractual restrictions contained in the instruments governing its indebtedness, including its credit facility.

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.

NON-GAAP FINANCIAL MEASURES

This Annual Information Form and certain documents incorporated by reference herein make reference to certain financial measures that are not recognized by GAAP. Non-GAAP financial measures do not have standardized meanings prescribed by GAAP and therefore may not be comparable to similar measures presented by other issuers. Investors are cautioned that these non-GAAP financial measures should not be construed as alternatives to other measures of financial performance calculated in accordance with GAAP. For information regarding the non-GAAP financial measures used by Tourmaline, see "Non-GAAP Financial Measures" in Tourmaline's MD&A for the year ended December 31, 2019, which section is incorporated by reference herein. The Financial Statements and MD&A are available on SEDAR at www.sedar.com.

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

DRILLING LOCATIONS

This document discloses drilling locations, as at December 31, 2019, in four categories: (i) proved undeveloped locations; (ii) probable undeveloped locations; (iii) unbooked locations; and (iv) an aggregate total of (i), (ii) and (iii). Of the 14,454 (gross) locations, 1,188 are proved undeveloped locations, 39 are proved non-producing locations, 1,008 are probable undeveloped locations and 12,219 are unbooked locations. Proved undeveloped locations, proved non-producing locations, probable undeveloped locations and probable non-producing locations are booked and derived from the Consolidated Reserve Report and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates based on the Company's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources (including contingent and prospective). Unbooked locations have been identified by management as an estimation of the Company's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While a certain number of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

SCHEDULE "A"

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, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, 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.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. 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.

5. The following table shows the net present value of 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 for the year ended December 31, 2019, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective 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 - $MM)			
			Audited	**Evaluated**	**Reviewed**	**Total**
Deloitte	December 31, 2019	Canada	-	$2,972.8	-	**$2,972.8**
GLJ Petroleum Consultants	December 31, 2019	Canada	-	$11,894.3	-	**$11,894.3**
*GLJ Petroleum Consultants	December 31, 2019	Canada	-	$226.2	-	**$226.2**
Total			-	$15,093.3	-	**$15,093.3**

*Gas Marketing Premium for all gas sales outside of Western Canadian markets

6. In our opinion, the reserves data 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.

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

8. 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, February 25, 2020.

ORIGINALLY SIGNED BY

"Originally signed by"

Chad P. Lemke, P. Eng.
Executive Vice President and COO

Deloitte, Calgary, Alberta, Canada, February 25, 2020.

ORIGINALLY SIGNED BY

"Originally signed by"

Andrew Botterill
Partner, Resource Evaluation and Advisory

SCHEDULE "B"

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.

GLJ Petroleum Consultants Ltd. and Deloitte LLP, 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

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

(b) the filing of Form 51-102F2 which is the reports of the independent qualified reserves evaluators on the reserves data, contingent resources data, or prospective resources data; and

(c) the content and filing of this report.

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

DATED as of this 3rd day of March, 2020.

(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)	*"Andrew B. MacDonald"* Andrew B MacDonald Director	(signed)	*"Lee A. Baker"* Lee A. Baker Director

SCHEDULE "C"

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:

1. 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, including compliance with legal and regulatory requirements;
2. To provide better communication between Directors and external auditors;
3. To enhance the external auditor's independence;
4. To increase the credibility and objectivity of financial reports, the financial reporting process and internal controls over financial reporting;
5. 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;
6. To maintain oversight of risk identification, assessment and management programs; and
7. To establish procedures for the receipt, retention and treatment of complaints received by the Company regarding accounting, internal controls or auditing matters.

Membership of Committee

1. The Board, on recommendation of the Governance Committee, will appoint members to the Committee. 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, on recommendation of the Governance Committee, 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; identify, monitor and mitigate 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;
    - obtaining explanations of significant variances with comparative reporting periods; and
    - determining through inquiry if there are any related party transactions and ensuring that the nature and extent of such transactions are properly disclosed.

4. In addition to the review of financial statements and MD&A described above, review prospectuses, 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;
    - monitor the relationship between management and the external auditor including reviewing any management letters or other reports of the external auditor and discussing any material differences of opinions between management and the external auditor;

- 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, third party credit risk and insurance). In this regard, the Committee shall:

   - Regularly identify and review the principal business risks, including potential emerging risks, of the Company and the actions taken by the Company to mitigate the risks;
   - Regularly identify and review the principal financial risks and exposures of the Company, together with mitigating strategies, including physical and financial positions in commodities markets, derivatives strategies, capital commitments, foreign exchange exposures, and exposure to interest rate fluctuations;
   - Regularly review the policies and activities of the Company's treasury and marketing groups and the financial risks arising from those activities, including any proposed authorities of Management from the Board for the hedging of the exposures; and
   - Review, and if desirable, recommend changes to the insurance program including coverage for property damage, business interruption and liabilities.

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 not be entitled to a second or casting vote and in such cases, the undecided matter should be referred to the Board as a whole.

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. At each meeting, the Committee will meet in camera without management present.

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.

12. In discharging its duties under this Mandate, the Committee may investigate any matter brought to its attention and will have access to all books, records, facilities and personnel, may conduct meetings or interviews of any officer or employee, the Company's legal counsel, external auditors and consultants and may invite any such other persons to attend any part of any meeting of the Committee.

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. MacDonald (Chair), Lamoreaux, Wigham and Ms. Angevine. 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)**
	($)	**($)**	**($)**	**($)**
2019	1,230,000	100,000	13,920	250,000(5)
2018	1,200,000	100,000	18,945	–
2017	1,050,000	100,000	22,850	350,000(5)

Notes:

(1) Represents the aggregate fees billed by the Company's external auditor in each of the last three fiscal years for services that are reasonably related to the performance of the audit or review of the Company's financial statements. The fees disclosed under this category also include the conduct of due diligence procedures in connection with financings and acquisitions undertaken by the Company.

(2) Represents the aggregate fees related to the French translation of the annual and quarterly financial statements and MD&A.

(3) Represents the aggregate fees billed in each of the last three 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 three 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".

(5) Represents fees billed by the Company’s external auditor related to a royalty recovery audit engagement.