Touchstone Exploration Inc.

Management's Discussion and Analysis

September 30, 2018

The following Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of Touchstone Exploration Inc. ("Touchstone", "we", "our", "us" or the "Company") for the three and nine months ended September 30, 2018 is dated November 13, 2018 and should be read in conjunction with the Company's unaudited interim consolidated financial statements for the three and nine months ended September 30, 2018, as well as the Company's audited consolidated financial statements for the year ended December 31, 2017. The unaudited interim consolidated financial statements and the audited consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board. This MD&A should also be read in conjunction with Touchstone's MD&A for the year ended December 31, 2017, as disclosure which is unchanged from December 31, 2017 may not be duplicated herein.

Additional information related to Touchstone and factors that could affect the Company's operations and financial results are included with reports on file with the Canadian securities regulatory authorities, including the Company's 2017 Annual Information Form dated March 26, 2018, which can be found on the Company's SEDAR profile (www.sedar.com).

Unless otherwise stated, tabular amounts herein are in thousands of Canadian dollars ("$" or "Cdn$"), and amounts in text are rounded to thousands of Canadian dollars. The Company may also reference United States dollars ("US$") and Trinidad and Tobago dollars ("TT$") herein, which are the functional and operational currencies of the Company's subsidiaries. All production volumes disclosed herein are sales volumes. Certain prior year amounts have been reclassified to conform to current year presentation. This MD&A contains forward-looking statements and non-GAAP measures. Readers are cautioned that the MD&A should be read in conjunction with Touchstone's disclosure under the sections titled "*Forward-looking Statements,*" "*Non-GAAP Measures*," and "*Abbreviations*".

About Touchstone Exploration Inc.

Touchstone is incorporated under the laws of Alberta, Canada with its head office located in Calgary, Alberta. The Company is an oil and gas exploration and production company active in the Republic of Trinidad and Tobago ("Trinidad"). Touchstone is one of the largest independent onshore oil producers in Trinidad, with assets in several large, high-quality reservoirs that have significant internally estimated total petroleum initially-in-place and an extensive inventory of low-risk development opportunities. The Company's common shares are traded on the Toronto Stock Exchange and the AIM market of the London Stock Exchange ("AIM") under the symbol "TXP".

Touchstone's strategy is to leverage western Canadian enhanced oil recovery experience and capability to international onshore properties to create shareholder value. Outside of its core Trinidad portfolio, the Company will continue to examine opportunities in jurisdictions that have stable political and fiscal regimes coupled with large defined original oil in place.

Third Quarter 2018 Highlights

- Achieved quarterly average crude oil production of 1,758 bbls/d, representing increases of 2% and 22% from the second quarter of 2018 and the third quarter of 2017, respectively.
- Continued our 2018 development program with total drilling and development capital expenditures of $4,543,000, drilling three wells and performing 12 well recompletions.
- Realized $12,890,000 in petroleum sales, a 63% increase from the prior year third quarter.
- Generated an operating netback of $37.13 per barrel, a 52% increase relative to the $24.46 per barrel generated in the prior year comparative quarter.

- Delivered funds flow from operations of $3,260,000 ($0.03 per basic share) compared to $1,387,000 ($0.01 per basic share) in the third quarter of 2017.
- Recognized net earnings of $267,000 compared to a net loss of $1,203,000 reported in the equivalent quarter of 2017.
- Exited the quarter with net debt of $12,975,000, representing 1.0 times net debt to third quarter 2018 annualized funds flow from operations.

Financial and Operating Results Summary

	Three months ended			Nine months ended	
	September 30, 2018	June 30, 2018	September 30, 2017	**September 30, 2018**	September 30, 2017
Operating					
Average daily oil production *(bbls/d)*	**1,758**	1,717	1,437	**1,674**	1,351
Net wells drilled	**3**	3	1	**8**	4
Net wells recompleted	**12**	4	3	**21**	13
Brent benchmark price *(US$/bbl)*	**75.10**	74.53	52.10	**72.15**	51.75
Operating netback[1] *($/bbl)*					
Realized sales price	**79.71**	80.04	59.64	**78.32**	61.58
Royalties	**(20.52)**	(22.59)	(14.59)	**(21.46)**	(17.07)
Operating expenses	**(22.06)**	(19.26)	(20.59)	**(20.46)**	(21.81)
	37.13	38.19	24.46	**36.40**	22.70
Financial *($000's except share and per share amounts)*					
Petroleum sales	**12,890**	12,508	7,885	**35,782**	22,712
Funds flow from operations	**3,260**	3,258	1,387	**9,119**	2,218
Per share – basic[1]	**0.03**	0.03	0.01	**0.07**	0.02
Per share – diluted[1]	**0.02**	0.03	0.01	**0.07**	0.02
Net earnings (loss)	**267**	(692)	(1,203)	**(300)**	(4,600)
Per share – basic and diluted	**0.00**	(0.01)	(0.01)	**(0.00)**	(0.05)
Capital expenditures					
Exploration	**578**	434	202	**1,240**	910
Development	**4,543**	4,520	1,889	**12,684**	7,375
	5,121	4,954	2,091	**13,924**	8,285
Net debt[1] – end of period					
Working capital surplus	**(2,025)**	(3,734)	(402)	**(2,025)**	(402)
Principal long-term balance of loan	**15,000**	15,000	15,000	**15,000**	15,000
	12,975	11,266	14,598	**12,975**	14,598
Weighted average shares outstanding					
Basic	**129,021,428**	129,021,428	103,137,143	**129,021,428**	90,243,370
Diluted	**130,728,340**	129,021,428	103,137,143	**129,021,428**	90,243,370
Outstanding shares – end of period	**129,021,428**	129,021,428	103,137,143	**129,021,428**	103,137,143

Note:
(1) See "*Non-GAAP Measures*".

Operating results

In the third quarter we continued with our expanded 2018 drilling campaign by successfully drilling three wells, bringing the total to eight development wells drilled through September 30, 2018. Capital expenditures totaled $5,121,000, of which $4,543,000 related to drilling and development activities. We recompleted 12 wells in the quarter, with an aggregate 21 wells recompleted through September 30, 2018.

Third quarter 2018 crude oil production averaged 1,758 bbls/d, a 22% increase relative to the 1,437 bbls/d produced in the third quarter of 2017. Third quarter average daily production increased 2% from the second quarter of 2018, with growth slowed by weather based electrical supply disruptions and higher than normal crude oil inventory held at September 30, 2018.

The eight wells drilled in 2018 combined to add approximately 249 bbls/d of incremental production in the third quarter, despite two new wells beginning to produce in mid-August and one well initiating production at the end of September. The four wells drilled in 2017 continued to perform above internal expectations, contributing approximately 351 bbls/d of production in the quarter.

Financial results

Our third quarter operating netback was $6,004,000 ($37.13 per barrel), an improvement of 86% compared to $3,234,000 ($24.46 per barrel) recorded in the third quarter of 2017. Higher realized prices and production resulted in a $5,005,000 increase in petroleum sales relative to the third quarter of 2017. This was offset by higher royalties of $1,390,000 from increased production and the sliding scale effect of increased commodity pricing to royalty rates. Operating costs increased by $845,000 from the prior year comparative quarter based on variable costs from increased production and increased well site security and monitoring costs.

We generated funds flow from operations of $3,260,000 in the third quarter of 2018 versus $1,387,000 in the equivalent quarter of 2017. The increase in funds flow was largely attributed to stronger realized crude oil pricing and operating netback combined with a 22% increase in production. As a result, we generated net earnings of $267,000 in the quarter, compared to a net loss of $1,203,000 reported in the prior year comparative quarter.

We maintained stable financial liquidity, exiting the quarter with positive working capital of $2,025,000 and a $15,000,000 principal term loan balance. Our September 30, 2018 net debt of $12,975,000 represented net debt to trailing twelve-month funds flow from operations of 1.3 times and net debt to third quarter 2018 annualized funds flow from operation of 1.0 times.

Principal Properties

The Company holds interests in producing and exploration properties in southern Trinidad and undeveloped acreage in Saskatchewan. All properties are operated by Touchstone apart from the Cory Moruga exploration block. A full schedule of the Company's property interests as of September 30, 2018 is set out in the table below:

Property[(1)]	Working interest	Lease type	Gross acres[(2)]	Net acres[(3)]
Trinidad				
Producing				
Coora 1	100%	Lease Operatorship	1,230	1,230
Coora 2	100%	Lease Operatorship	469	469
WD-4	100%	Lease Operatorship	700	700
WD-8	100%	Lease Operatorship	650	650
New Dome	100%	Farmout Agreement	69	69
South Palo Seco	100%	Farmout Agreement	2,167	2,167
Barrackpore	100%	Private	211	211
Fyzabad	100%	Crown	94	94
Fyzabad	100%	Private	470	470
Palo Seco	100%	Crown	499	499
San Francique	100%	Private	1,351	1,351
	100%		**7,910**	**7,910**
Exploratory				
Bovallius	100%	Private	827	827
Cory Moruga	16%	Crown	11,969	1,939
East Brighton	70%	Crown	20,589	14,412
Moruga	100%	Private	1,416	1,416
New Grant	100%	Private	193	193
Ortoire	80%	Crown	44,731	35,785
Rousillac	100%	Private	235	235
Siparia	50%	Private	111	56
St. John	100%	Private	179	179
	69%		**80,250**	**55,042**
	71%		**88,160**	**62,952**
Canada				
Exploratory				
Beadle[(4)]	100%	Freehold	2,240	2,240
Luseland[(5)]	100%	Crown & Freehold	5,171	5,171
	100%		**7,411**	**7,411**
Total	**73%**		**95,571**	**70,363**

Notes:
(1) The table excludes the Company's Icacos property that was classified as held for sale at September 30, 2018.
(2) "Gross" means acres in which the Company has an interest.
(3) "Net" means the Company's interest in the gross acres.
(4) All of the Company's Beadle acreage expires on March 31, 2019.
(5) Approximately 25% of the Company's Luseland acreage expires on March 31, 2019.

Operating Agreements

In Trinidad, the Company operates under lease operatorship agreements ("LOAs") and farmout agreements ("FOAs") with the Petroleum Company of Trinidad and Tobago Limited ("Petrotrin"), state exploration and production licences with the Trinidad and Tobago Minister of Energy and Energy Industries ("MEEI"), and private exploration and production agreements with individual landowners.

Lease operatorship agreements

The Company's LOAs governing its four core properties (Coora 1, Coora 2, WD-4 and WD-8) with Petrotrin expire on December 31, 2020, with the Company holding a five-year renewal options upon reaching agreements regarding the proposed work programs and financial obligations. The practice in Trinidad is for extensions to be issued in most cases on terms substantially similar to those in effect at the time. Presently, the Company is subject to annual minimum production levels and five-year minimum work commitments from 2016 through 2020. Under the LOAs, failing to reach minimum production levels does not constitute a breach provided the minimum work obligations have been completed.

As of September 30, 2018, the Company satisfied all of its minimum work obligations stipulated in its LOAs through December 31, 2020, which included drilling 10 wells and performing eleven recompletions.

Farmout agreements

The Company's farmout agreements with Petrotrin expire on December 31, 2021. The Company holds a five-year renewal option, and the agreements are subject to five-year minimum work commitments from 2017 through 2021. The Company satisfied its 2017 FOA work commitments in 2017. The Company's FOA work commitments from 2018 to 2020 and status as at the date of this MD&A are as follows:

FOA	**2018**		**2019**		**2020**	
	Commitment	**Status**	**Commitment**	**Status**	**Commitment**	**Status**
New Dome	1 recompletion	Completed	n/a	n/a	1 recompletion	**Outstanding**
South Palo Seco	1 drill 1 recompletion	**Outstanding** Completed	1 drill 1 recompletion	**Outstanding** **Outstanding**	1 recompletion	**Outstanding**

In addition, the South Palo Seco FOA specifies the performance of one well recompletion in 2021 which has not been performed to date. The Company anticipates drilling the South Palo Seco 2018 and 2019 obligation wells in the second half of 2019, subject to customary regulatory approvals (see the "*Contractual Obligations, Commitments and Guarantees*" section for further details).

MEEI exploration and production licences

The Company has exploration and production licences with the MEEI for its Fyzabad and Palo Seco producing properties and its Cory Moruga, East Brighton and Ortoire exploration properties. The licences typically are for an initial six-year term, with the option to extend a further 19 years upon a commercial discovery. Under its East Brighton and Ortoire licences, the Company is subject to work commitments through 2020 (see the "*Contractual Obligations, Commitments and Guarantees*" section for further details).

The Company's Fyzabad and Palo Seco agreements with the MEEI contain no major work obligations or covenants; however, both licences expired on August 19, 2013. The Company negotiated an extension of the Fyzabad licence to August 19, 2032 in the third quarter of 2018.

The Company is currently negotiating a renewal or extension of the Palo Seco licence and has permission from the MEEI to operate in the interim period. The Company has no indication that the licence will not be renewed. During the three and nine months ended September 30, 2018, production volumes produced under the expired Palo Seco licence represented 0.8% and 0.8% of total production, respectively (2017 – 1.1% and 1.1%).

Private lease agreements

Touchstone also negotiates private lease agreements with individual land owners. Lease terms are typically 35 years in duration and contain no minimum work obligations.

The Company is operating under a number of Trinidad private lease agreements which have expired and are currently being renewed. Based on legal opinions received, Touchstone is continuing to recognize revenue on the producing properties because the Company is the operator, is paying all associated royalties and taxes, and no title to the revenue has been disputed. The Company currently has no indication that any of the producing expired leases will not be renewed. The continuation of production from expired private leases during the renegotiation process is common in Trinidad. During the three and nine months ended September 30, 2018, production volumes produced under expired private lease agreements represented 2.3% and 2.4% of total production, respectively (2017 – 3.1% and 3.0%).

Crude oil marketing agreement

On January 14, 1974, Premier Consolidated Oilfields Limited, the Company's predecessor in interest, and Texaco Trinidad Inc., Petrotrin's predecessor, entered into a Crude Oil Purchase Agreement whereby Petrotrin committed to purchase all petroleum crude oil produced by Primera Oil and Gas Limited from various producing properties. The agreement, as amended from time to time, has continued to have an indefinite term and may be terminated by either party on three months notice. The price currently paid is the Petrotrin equity land blend indexed price, payable in US$. The parties are in discussions on a new Crude Oil Purchase Agreement.

Petrotrin restructuring

On August 28, 2018, Petrotrin announced its intention to restructure its operations, which includes exiting its refining business and remodeling its exploration and production business. Petrotrin's exploration and production business will be transferred to and operated under the newly established Heritage Petroleum Company. Petrotrin intends to transition from buying oil for refining to that of exporting oil and importing refined products for sales and distribution under the newly established Paria Fuel Trading Company. This transition period commenced September 1, 2018 and is expected to be completed prior to the end of the year. Petrotrin exported its first cargo of crude on October 30, 2018.

Four of the Company's five core properties are secured by LOAs with Petrotrin. Under these arrangements, the Company has subleased petroleum production and exploration rights from Petrotrin and is obligated to sell all produced volumes to Petrotrin. The Company's Fyzabad core property is leased directly from land owners and the MEEI. Petrotrin is currently the Company's sole purchaser of crude oil.

The Company has been informed via written correspondence from the Chairman of Petrotrin that the national oil company will continue to meet its contractual operations and commitments throughout the transition process. Petrotrin has indicated that it will be meeting with all pertinent stakeholders following completion of the restructuring to discuss future changes and opportunities.

Although the Company currently has no indication, there can be no assurance that Petrotrin will not revoke or significantly alter the conditions of the Company's LOAs, which could have a material adverse effect on the Company's future operations and viability. Given that Petrotrin is currently the Company's sole purchaser of crude oil, any disruptions with current operations 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. Any significant change in current marketing factors could harm the Company's business and, in turn, have a material adverse impact on the financial position and future prospects of the

Company. In addition, the restructuring of Petrotrin may involve significant labour unrest, which could have an adverse effect on the Company's field operations and cash flows.

Economic Environment

Selected benchmark prices and exchange rates

Touchstone's third quarter and year to date 2018 financial and operating results were impacted by commodity prices and foreign exchange rates which are outlined below.

	Three months ended September 30,		% change	Nine months ended September 30,		% change
	2018	2017		**2018**	2017	
Average Crude oil benchmark prices[(1)]						
Brent *(US$/bbl)*	**75.10**	52.10	44	**72.15**	51.75	39
WTI *(US$/bbl)*	**69.50**	48.20	44	**66.75**	49.46	35
Average foreign exchange rates[(2)]						
Cdn$:US$	**0.77**	0.80	(4)	**0.78**	0.77	1
Cdn$:TT$	**5.16**	5.38	(4)	**5.23**	5.16	1
US$:TT$	**6.74**	6.75	-	**6.73**	6.74	-

Notes:
(1) Source: US Energy Information Administration. Benchmark prices do not reflect the Company's realized sales prices. Refer to "*Realized prices excluding derivative contracts*".
(2) Source: Oanda Corporation average daily exchange rates for the specified periods.

Touchstone's crude oil realized price has historically correlated to the Brent benchmark price. Global crude oil prices continued to strengthen in the third quarter of 2018, with the US$ denominated Brent reference price averaging 1% higher than the second quarter of 2018 and 44% higher than the third quarter of 2017. Robust global demand and relatively balanced supply-demand levels contributed to the continued rise in crude prices. However, subsequent to the end of the third quarter, global crude oil prices have retreated in excess of 10%.

The Canadian dollar was range bound relative to the US$ during the third quarter of 2018, averaging US$0.77 (US$/Cdn$ - 1.31). The TT$ continued to remain range-bound relative to the US$ during the third quarter, averaging US$0.15 (US$/TT$ - 6.74).

2018 Third Quarter and Year to Date Results of Operations

The Company's operations are conducted in Trinidad. The Company's operations are viewed as a single operating segment by the chief operating decision maker of the Company for the purposes of resource allocation and assessing performance.

Production volumes

	Three months ended September 30,		% change	Nine months ended September 30,		% change
	2018	2017		**2018**	2017	
Oil production *(bbls)*	**161,716**	132,199	22	**456,889**	368,794	24
Average daily oil production *(bbls/d)*	**1,758**	1,437	22	**1,674**	1,351	24

Production volumes by property

(bbls)	Three months ended September 30, **2018**	2017	% change	Nine months ended September 30, **2018**	2017	% change
Coora 1	**36,766**	30,782	19	**102,819**	57,806	78
Coora 2	**6,852**	5,464	25	**19,126**	18,518	3
WD-4	**53,839**	44,553	21	**162,417**	129,584	25
WD-8	**30,558**	21,621	41	**84,783**	74,434	14
New Dome	**2,441**	2,516	(3)	**7,016**	6,797	3
South Palo Seco	**779**	853	(9)	**1,916**	1,426	34
Barrackpore	**8,123**	3,981	100	**13,354**	11,216	19
Fyzabad	**12,957**	12,032	8	**38,824**	39,337	(1)
Icacos	**1,010**	952	6	**3,109**	2,949	5
Palo Seco	**1,265**	1,374	(8)	**3,610**	3,828	(6)
San Francique	**7,126**	8,071	(12)	**19,915**	22,899	(13)
Production	**161,716**	132,199	22	**456,889**	368,794	24

Third quarter 2018 crude oil production increased 22% from the third quarter of 2017 as a result of an active and successful drilling and completion program in 2017 and 2018. The four wells drilled in 2017 and eight wells drilled in 2018 combined to contribute approximately 600 bbls/d of production in the third quarter of 2018, whereas the four wells drilled in 2017 contributed a combined 273 bbls/d of production in the third quarter of 2017.

In the first nine months of 2018, crude oil production increased 24% as compared to the same period in 2017 based on production gains achieved from the Company's aforementioned drilling and recompletion efforts, which contributed average production of approximately 489 bbls/d in the year to date 2018 period. In the comparative 2017 period, the 2017 drilling program contributed an incremental 104 bbls/d.

Realized prices excluding derivative contracts

	Three months ended September 30, **2018**	2017	% change	Nine months ended September 30, **2018**	2017	% change
Realized price (*US$/bbl*)	**60.78**	47.53	28	**60.60**	47.13	29
US$ realized price discount as a % of Brent	**19.1**	8.8		**16.0**	8.9	
US$ realized price discount as a % of WTI	**12.5**	1.4		**9.2**	4.7	
Realized price (*Cdn$/bbl*)	**79.71**	59.64	34	**78.32**	61.58	27

The Company's crude oil price received is based on quality differentials and prices realized from Petrotrin refined products. The differential to Brent reference pricing realized during the three and nine months ended September 30, 2018 widened to 19.1% and 16.0%, respectively (2017 – 8.8% and 8.9%).

In the third quarter of 2018, the Company's realized Trinidad crude oil price was $79.71 per barrel compared to $59.64 per barrel in the same period of 2017. The 34% increase was a result of a 44% increase in the US$ Brent reference price over the same period, partially offset by an increase in the realized Brent reference differential from 8.8% to 19.1%.

On a year to date basis, the Company's realized crude oil price in 2018 was 27% higher versus the comparative 2017 period. The realized price increase was a result of a 39% increase in the Brent reference price over the same period, partially offset by an increase in the realized Brent reference differential and a stronger Canadian dollar.

Petroleum sales

($000's)	Three months ended September 30, **2018**	2017	% change	Nine months ended September 30, **2018**	2017	% change
Petroleum sales	**12,890**	7,885	63	**35,782**	22,712	58

The Company recognized petroleum sales of $12,890,000 during the three months ended September 30, 2018. This represented a 63% increase from the corresponding 2017 period as realized pricing and production increased by 34% and 22%, respectively.

The Company's petroleum sales for the first nine months of 2018 were $35,782,000 versus $22,712,000 in the comparative 2017 period. The 58% year to date increase was based on a 27% increase in realized pricing and a 24% increase in production.

Touchstone sells its crude oil to Petrotrin, who establishes a monthly realized sales price. As at September 30, 2018, the Company held 9,617 barrels of crude oil inventory versus 8,612 barrels held as at December 31, 2017. The Company's crude oil is typically sold to Petrotrin three days per week, with title transferring at the Company's various sales batteries.

Commodity price financial derivatives

The Company may enter into crude oil financial derivative contracts to protect funds flow from operations from the volatility of commodity prices. Touchstone's strategy focuses on the use of puts, costless collars, swaps or fixed price contracts to limit exposure to fluctuations in commodity prices while allowing for participation in commodity price increases. Touchstone does not employ hedge accounting for any of its risk management contracts.

In January 2018, the Company purchased crude oil put option contracts for 500 bbls/d at a strike price of Brent US$55.00 per barrel from March 1, 2018 to December 31, 2018. The put options were purchased from a financial institution for an upfront cash premium of US$153,000 ($190,000). The options may be settled on a monthly basis during the option exercise period. For the three and nine months ended September 30, 2018, the Company recorded derivative losses of $13,000 and $198,000, respectively (2017 - $nil and $nil) related to the commodity management contracts. For further information, refer to the *"Risk Management"* section of this MD&A.

Other income

In the first quarter of 2018, the Company sold a licensed 3D seismic copy of the Luseland, Saskatchewan area to a third-party broker for proceeds of $484,000 (2017 - $nil).

Royalties

($000's unless otherwise stated)	Three months ended September 30, **2018**	2017	% change	Nine months ended September 30, **2018**	2017	% change
Crown royalties	**1,383**	787		**3,794**	2,591	
Private royalties	**215**	141		**553**	434	
Overriding royalties	**1,721**	1,001		**5,458**	3,272	
Royalties	**3,319**	1,929	72	**9,805**	6,297	56
As a percentage of petroleum sales	**25.7%**	24.5%	5	**27.4%**	27.7%	(1)

Touchstone incurs a crown royalty rate of 12.5% on gross production under MEEI and Petrotrin leases. For private leases, the Company incurs private royalties between 10% and 12.5% of gross petroleum sales. On the WD-8, Coora and WD-4 blocks, the Company operates under LOAs, which in addition to crown royalties apply a sliding scale notional overriding royalty ("NORR") that ranges from 10% to 35% on predefined monthly base production levels. For any production volumes sold in excess of base production levels, the Company incurs an enhanced NORR ("enhanced NORR") of 8% to 22.5%. The NORR and enhanced NORR rates are indexed to the price of oil realized in the production month. The LOAs allow for NORR and enhanced NORR incentives for the drilling or sidetracking of a replacement well as follows:

- Year 1 of production from the replacement well: 0% NORR or enhanced NORR rate; and
- Year 2 of production from the replacement well: 10% NORR or enhanced NORR rate.

In addition to crown royalties, the South Palo Seco and New Dome blocks operate under FOAs that stipulate NORR rates ranging from 7% to 27% and enhanced NORR rates ranging from 4% to 17%. Similar to the LOA structure, the NORR and enhanced NORR rates are indexed to the price of oil realized in the production month. However, there are no incentives for drilling under the FOAs.

During the three months ended September 30, 2018, royalties represented 25.7% of petroleum sales compared to 24.5% in the prior year comparative period. The 5% increase on a percentage of petroleum sales basis reflected the sliding scale effect of increased commodity prices to royalty rates.

Royalty expenses were 27.4% of petroleum revenue during the nine months ended September 30, 2018 versus 27.7% in the corresponding prior year period. The 1% percentage of sales decrease from 2017 was based on a one-time $353,000 adjustment recognized in the first quarter of 2017 that related to prior period impost levies that were invoiced in March 2017.

Operating expenses

($000's)	**Three months ended September 30,**		% change	**Nine months ended September 30,**		% change
	2018	2017		**2018**	2017	
Operating expenses	**3,567**	2,722	31	**9,349**	8,043	16

The Company's third quarter operating expenses were $3,567,000, representing $22.06 per barrel or US$16.89 per barrel. In comparison to the same period of 2017, operating costs increased 31% on an absolute basis and 7% on a per barrel basis. The per barrel increase was predominantly from increased well site security and monitoring costs, which are expected to marginally decrease going forward.

During the first nine months of 2018, operating expenses were $9,349,000, representing $20.46 per barrel or US$15.92 per barrel. The per barrel decrease of $1.35 or 6% from the comparative 2017 period was mainly attributable to decreased well servicing and transportation expenses from 2017.

Operating netback(1)

($/bbl)	**Three months ended September 30,**		% change	**Nine months ended September 30,**		% change
	2018	2017		**2018**	2017	
Brent benchmark price(2)	**98.17**	65.28	50	**92.95**	67.61	37
Discount	**(18.46)**	(5.64)		**(14.63)**	(6.03)	
Realized sales price	**79.71**	59.64	34	**78.32**	61.58	27
Royalties	**(20.52)**	(14.59)	41	**(21.46)**	(17.07)	26
Operating expenses	**(22.06)**	(20.59)	7	**(20.46)**	(21.81)	(6)
Operating netback	**37.13**	24.46	52	**36.40**	22.70	60

Notes:
(1) See "*Non-GAAP Measures*".
(2) Source: US Energy Information Administration. Canadian price was calculated using average Oanda Corporation daily exchange rates for the specified periods.

Third quarter 2018 operating netback was $37.13 per barrel, representing a 52% increase from the $24.46 per barrel recognized in the same period of 2017. Compared to the third quarter of 2017, realized prices per barrel increased by 34%. Royalty expenses per barrel increased 41% based on the rising scale effect of increased average commodity prices to royalty rates. Third quarter 2018 operating costs per barrel increased 7% from the third quarter of 2017, predominantly from increased well site security and monitoring costs.

During the nine months ended September 30, 2018, operating netback was $36.40 per barrel compared to $22.70 per barrel in the comparative 2017 period. Year to date 2018 realized prices per barrel increased 27% from 2017, and related royalties per barrel increased commensurate with realized pricing. Year to date September 30, 2018 operating expenses were $20.46 per barrel, which represented a 6% decrease from the $21.81 per barrel incurred in 2017 based on reduced well servicing and transportation expenses.

General and administrative ("G&A") expenses

($000's)	**Three months ended September 30, 2018**	2017	% change	**Nine months ended September 30, 2018**	2017	% change
Gross G&A expenses	**1,973**	1,779	11	**6,156**	5,284	17
Capitalized G&A expenses	**(319)**	(212)	50	**(901)**	(646)	39
G&A expenses	**1,654**	1,567	6	**5,255**	4,638	13

For the three months ended September 30, 2018, G&A expenses were $1,654,000, representing an increase of $87,000 or 6% from the comparative 2017 period. The increase was predominately due to increases in staffing costs, consultant expenses and director fees.

For the first nine months of 2018, G&A expenses increased $617,000 or 13% from the prior year equivalent period. The year to date variance was predominately due to the aforementioned increases in salaries and benefits, director fees and consultant expenses. In addition, the Company incurred $96,000 in the first quarter of 2018 for severance charges from the elimination of its internal security department in favour of a third-party contractor. Further increases in 2018 were attributable to AIM listing related costs that were not incurred in the first six months of the prior year and increases in annual general meeting costs for the 2018 meeting held in Trinidad. Year to date per barrel 2018 G&A costs reduced 9% from the same period in the prior year to $11.50 per barrel, predominately from increased 2018 production.

Net finance (income) expense

($000's)	**Three months ended September 30, 2018**	2017	% change	**Nine months ended September 30, 2018**	2017	% change
Interest income	**(57)**	(34)		**(172)**	(68)	
Interest expense on term loan	**303**	303		**898**	898	
Term loan revaluation gain	**-**	-		**(283)**	-	
Production payment liability revaluation (gain) loss	**(350)**	-		**59**	-	
Interest (recovery) expense on taxes / other	**-**	(2)		**5**	599	
Net finance (income) expense	**(104)**	267	(100)	**507**	1,429	(65)

Interest income included interest earned from funds on deposit and interest generated from a finance lease (see "*Capital Expenditures and Dispositions Resources – Capital lease*").

2018 term loan interest expense remained consistent with the prior year in both periods, as the Company's $15 million term loan bears an 8% fixed interest rate.

The term loan revaluation gain represented the impact of the revaluation of the Company's term loan that was extended by one-year in June 2018. The production payment liability revaluation net loss was a result of the increased production payment liability estimated by the Company as at September 30, 2018. The estimated liability increased on a year to date basis based on a corresponding one-year extension of the obligation in June 2018 and changes to internally forecasted production and forward commodity pricing (see "*Liquidity and Capital Resources - Term loan*").

In 2017, interest expenses on income taxes were accrued for outstanding value added tax balances owed as a result of intercompany transactions. The outstanding principal balances were fully paid in the second quarter of 2017 and incurred no further interest charges upon settlement.

Foreign exchange and foreign currency translation

The Company's presentation currency is the Canadian dollar. The Company and its Canadian subsidiaries have a Canadian dollar functional currency while its Trinidadian subsidiaries each has a Trinidad and Tobago dollar functional currency. Touchstone Exploration (Barbados) Ltd., a wholly-owned holding subsidiary of the Company, has a United States dollar functional currency. In each reporting period, the change in values of the US$ and TT$ relative to the Canadian dollar reporting currency are recognized.

The applicable rates used to translate the Company's TT$ and US$ denominated items were as follows:

	Three months ended September 30,		% change	Nine months ended September 30,		% change
	2018	2017		**2018**	2017	
Average foreign exchange rates(1)						
Cdn$:US$	**0.77**	0.80	(4)	**0.78**	0.77	1
Cdn$:TT$	**5.16**	5.38	(4)	**5.23**	5.16	1
US$:TT$	**6.74**	6.75	-	**6.73**	6.74	-
				September 30, 2018	December 31, 2017	% change
Closing foreign exchange rates(2)						
Cdn$:US$				**0.78**	0.80	(3)
Cdn$:TT$				**5.21**	5.39	(3)
US$:TT$				**6.72**	6.77	(1)

Notes:
(1) Source: Oanda Corporation average daily exchange rates for the specified periods.
(2) Source: Oanda Corporation daily exchange rates for the specified date.

The income and expenses of the Company's Trinidad operations are translated to Canadian dollars at the average monthly exchange rates relative to the date of the transactions. Specifically, the Company's revenues are subject to foreign exchange exposure as the sales prices of crude oil are determined by reference to US$ denominated benchmark prices. An increase in the value of the Canadian dollar compared with the US$ has a negative impact on the Company's reported results. Likewise, as the Canadian dollar weakens, the Company's reported results are higher. The Company's foreign currency risk also relates to working capital balances denominated in US$ and UK pounds sterling.

During the three and nine month periods ended September 30, 2018, the Canadian dollar average rate depreciated relative to both the US$ and TT$ and appreciated relative to the UK pound. The volatility in foreign exchange rates created a $76,000 loss in the third quarter of 2018 and a $241,000 gain during the nine months ended September 30, 2018 (2017 – losses of $299,000 and $534,000). The majority of the translation differences were unrealized in nature and may be reversed in the future as a result of fluctuations in prevailing exchange rates.

The assets and liabilities of the Company's subsidiaries are translated to Canadian dollars at the exchange rate on the reporting period date for presentation purposes. All resulting foreign currency differences are recorded in other comprehensive income in the Company's consolidated statements of comprehensive income (loss). The Canadian dollar was 2% stronger relative to both the US$ and TT$ as at September 30, 2018 compared to June 30, 2018. As a result, a foreign currency translation loss of $926,000 was reported during the third quarter of 2018 (2017 – loss of $1,796,000). As at September 30, 2018 compared to December 31, 2017, the Canadian dollar was 3% weaker relative to both the US$ and TT$, resulting in a foreign currency translation gain of $1,600,000 recorded during the nine months ended September 30, 2018 (2017 – loss of $2,967,000).

Share-based compensation

The Company has a share option plan pursuant to which options to purchase common shares of the Company may be granted by the Board of Directors to directors, officers, employees and consultants of the Company. The exercise price of each option may not be less than the closing price of the common shares prior to the date of grant. Compensation expense is recognized as the options vest. Unless otherwise determined by the Board of Directors, vesting typically occurs one third on each of the next three anniversaries of the date of the grant as recipients render continuous service to the Company, and the share options typically expire five years from the date of the grant.

On April 5, 2018, the Company awarded 1,018,800 share options to officers and employees at an exercise price of $0.22 per option. On June 13, 2018, the Company granted a further 670,000 share options to directors and employees at an exercise price of $0.25 per option. Under both grants, the share options have a five-year term and vest one third on each of the next three anniversaries of the grant date.

The Company also has an incentive share option plan which provides for the grant of incentive share options to purchase common shares of the Company at a $0.05 exercise price. A maximum of one million common shares have been approved for issuance under this plan. Unless otherwise determined by the Board of Directors, vesting typically occurs one third on each of the next three anniversaries of the date of the grant, and the incentive share options typically expire five years from the date of the grant.

The maximum number of common shares issuable on the exercise of outstanding share options and incentive share options at any time is limited to 10% of the issued and outstanding Company common shares. At September 30, 2018, share options and incentive share options outstanding represented 6.6% of the Company's outstanding common shares (December 31, 2017 – 5.3%).

During the three and nine months ended September 30, 2018, the Company recorded share-based compensation expenses of $41,000 and $115,000, respectively (2017 - $33,000 and $133,000).

Depletion and depreciation expense

($000's unless otherwise indicated)	**Three months ended September 30,**		% change	**Nine months ended September 30,**		% change
	2018	2017		**2018**	2017	
Depletion expense	**1,330**	967	38	**3,767**	2,966	27
On a per barrel basis	**8.22**	7.31	12	**8.24**	8.04	3
Depreciation expense	**40**	126	(68)	**122**	417	(71)
Depletion and depreciation expense	**1,370**	1,093	25	**3,889**	3,383	15

The Company’s producing assets in Trinidad are subject to depletion expense. The net carrying value of producing assets is depleted using the unit of production method by reference to the ratio of production in the period over the related proven and probable reserves while also considering the estimated future development costs necessary to bring those reserves into production. Assets in the exploration phase are not amortized. Depreciation expense is recorded based on corporate assets in Canada on a declining balance basis.

As at September 30, 2018, $76,394,000 in future development costs were included in the Trinidad production asset cost bases for depletion calculation purposes (September 30, 2017 - $58,349,000). For the three and nine months ended September 30, 2018, per barrel depletion expenses increased slightly in comparison to the prior year equivalent periods. The higher depletable base due to increased development capital spending and future development costs was offset by increased production throughout 2018.

Third quarter and year to date September 30, 2018 depreciation expenses decreased in comparison to the corresponding prior year periods due to lower asset carrying values. The Company’s oil service assets were leased to a third party effective October 1, 2017, resulting in decreased Trinidad based depreciation expenses booked throughout 2018.

Impairment

Entities are required to conduct impairment test where there is an indication of impairment or reversal of an asset, and the test may be conducted for a cash-generating unit (“CGU”) where an asset does not generate cash inflows that are largely independent of those from other assets. Impairment is recognized when the carrying value of an asset or group of assets exceeds its recoverable amount, defined as the higher of its value in use or fair value less costs of disposal. Any asset impairment that is recorded is recoverable to its original value less any associated depletion and depreciation expense should there be indicators that the recoverable amount of the asset has increased in value since the time of recording the initial impairment. Immediately before non-current assets are classified as held for sale, they are assessed for indicators of impairment or reversal of impairment and are measured at the lower of their carrying amount and fair value less costs of disposal, with any impairment loss or reversal of impairment recognized in net earnings. Touchstone assesses exploration asset and property and equipment indicators of impairment and impairment reversals on a quarterly basis. As future commodity prices remain volatile, impairment charges or recoveries could be recorded in future periods.

At September 30, 2018 and 2017, Touchstone evaluated its petroleum assets for indicators of any potential impairment or related reversal. As a result of these assessments, no indicators were identified, and no impairment or related reversal was recorded.

During the three and nine months ended September 30, 2018, the Company incurred $262,000 and $498,000 in lease expenses and letter of credit holding costs relating to its East Brighton property, respectively (2017 - $122,000 and $599,000). These costs were impaired given the property’s estimated recoverable value was $nil. During the nine months ended September 30, 2018, the Company incurred a further $40,000 impairment charge relating to its Cory Moruga exploration concession. The decommissioning liability associated with the property was increased based on changes in estimates, and the corresponding abandonment asset was impaired given the property’s estimated recoverable value was $nil. An additional $39,000 in corporate exploration property lease expenses were incurred and impaired during the nine months ended September 30, 2017.

Decommissioning obligations and abandonment fund

The Company’s decommissioning obligation liabilities relate to future site restoration and well abandonment costs including the costs of production equipment removal and land reclamation based on current environmental regulations.

Pursuant to production and exploration licences with the MEEI, the Company is obligated to remit US$0.25 per barrel sold into an escrow account in the name of the MEEI. The payments are used as a contingency fund for remediation of pollution arising from petroleum operations carried out under the licence and the eventual abandonment of wells and decommissioning of facilities used for operations conducted under the licence. The MEEI shall return the funds in the escrow account once all obligations in respect of environmental remediation are fulfilled to the satisfaction of the MEEI. Contributions to the fund are reflected on the statement of financial position as long-term abandonment fund assets.

With respect to decommissioning obligations associated with the Company's leases with Petrotrin, the Company is obligated for its proportional cost of all abandonments defined as its percentage of crude oil sold in a well in comparison to the well's cumulative historical production. The Company is not responsible for the decommissioning of existing infrastructure and sales facilities. The Company is obligated to remit US$0.25 per barrel sold to Petrotrin into a joint well abandonment fund. These funds are used solely for well decommissioning. Any costs of wells that are abandoned during the relevant agreement term are credited against any future contributions of the well abandonment fund. Upon expiration of the relevant agreement, Petrotrin shall calculate the Company's total abandonment liability. If Touchstone's liability exceeds the well abandonment fund, the Company is obligated to pay the difference. Conversely, if the proceeds of the fund exceed the liability, the surplus shall be returned to Touchstone. These amounts are reflected on the statement of financial position as long-term abandonment fund assets. As of September 30, 2018, the Company classified $1,214,000 of accrued or paid contributions into abandonment funds as long-term decommissioning obligation funds (December 31, 2017 - $1,049,000).

Pursuant to its Petrotrin operating agreements, the Company funds Petrotrin's US$0.25 per barrel obligation with respect Petrotrin's head licence with the MEEI. As the Company cannot access the contributions for its future well abandonments and all contributions are non-refundable, the payments are expensed as incurred. Additionally, the Company is obligated to remit US$0.03 per barrel to Petrotrin into a general abandonment fund. The non-refundable proceeds are used as a contingency fund for the decommissioning and removal of infrastructure and facilities within a property and are expensed as incurred.

The Company estimated the net present value of the cash flows required to settle its decommissioning obligations to be $12,580,000 at September 30, 2018 based on a total inflation adjusted future liability of $40,201,000 (December 31, 2017 - $11,853,000 and $39,193,000). At September 30, 2018 and December 31, 2017, decommissioning obligations were valued using a long-term risk-free rate of 6.1% and a long-term inflation rate of 3.3%. During the nine months ended September 30, 2018, the Company abandoned two wells resulting in a decommissioning loss of $11,000 (2017 - $nil). Accretion charges of $86,000 and $254,000 during the three and nine months ended September 30, 2018 were recognized to reflect the increase in decommissioning obligation associated with the passage of time, respectively (2017 - $37,000 and $116,000). Decommissioning obligation details as at September 30, 2018 were as follows:

Number of net well locations	**Undiscounted balance** *($000's)*	**Inflation adjusted balance** *($000's)*	**Discounted balance** *($000's)*
858	**20,295**	**40,201**	**12,580**

Environmental stewardship is a core value at Touchstone, and abandonment and reclamation activities are made in a prudent, responsible manner with the oversight of the Board. Decommissioning liabilities are considered critical accounting estimates. There are significant uncertainties related to decommissioning expenditures, and the impact on the consolidated financial statements could be material. The eventual timing of and costs for these expenditures could differ from current estimates. Further information regarding decommissioning liabilities for the three and nine months ended September 30, 2018 is included in Note 7 "*Decommissioning Obligations and Abandonment Fund*" to the Company's September 30, 2018 unaudited interim consolidated financial statements.

Income tax expense and income taxes payable

The Company's two Trinidad exploration and production subsidiaries are subject to the following Trinidad petroleum taxes:

- Supplemental Petroleum Tax ("SPT") 18% of gross oil revenue less royalties
- Petroleum Profits Tax ("PPT") 50% of net taxable profits
- Unemployment Levy ("UL") 5% of net taxable profits
- Green Fund Levy 0.3% of gross revenue

SPT is computed and remitted on a quarterly basis. Actual rates vary based on the realized selling prices of crude oil in the applicable quarter. The SPT rate is 0% when the weighted average realized price of oil for a given quarter is below US$50.00 per barrel and 18% when weighted average realized oil prices fall between US$50.00 and US$90.00. The revenue base for the calculation of SPT is gross revenue less royalties, less 20% investment tax credits for allowable tangible and intangible capital expenditures incurred in the applicable fiscal quarter.

Annual PPT and UL taxes are calculated based on net taxable profits. Net taxable profits are determined by calculating gross revenue less: royalties, SPT paid during the year, capital allowances, operating, administration and certain finance expenses. PPT losses may be carried forward indefinitely to reduce PPT in future years. UL losses cannot be carried forward to reduce future year UL. Developmental and exploratory capital expenditure allowances (tangible and intangible) are amortized 50% in year one, 30% in year two and 20% in year three. All unsuccessful development expenditures and abandonment costs can be written off in the year incurred.

The Company has a Trinidad oilfield service subsidiary that is subject to the greater of a 30% corporation income tax calculated on net taxable profits or a 0.6% business levy calculated on gross revenue. The service company is also subject to the green fund levy noted above. All corporate income tax losses can be carried forward indefinitely. Allowances vary from 10% to 33.3% for various capital expenditures incurred in the year. On October 1, 2017, the Company entered into a five-year contractual agreement to lease its four service rigs and ancillary equipment to a third party (see the "*Capital lease*" section for further details).

The following table summarizes current income tax expense for the three and nine months ended September 30, 2018 and 2017:

($000's)	**Three months ended September 30,**		% change	**Nine months ended September 30,**		% change
	2018	2017		**2018**	2017	
SPT	**825**	-		**1,621**	77	
PPT/UL	**-**	-		**103**	-	
Business levy	**6**	14		**17**	30	
Green fund levy	**42**	39		**123**	88	
Current income tax expense	**873**	53	100	**1,864**	195	100

Third quarter 2018 Trinidad based current income taxes were $873,000 versus $53,000 reported in the prior year equivalent quarter. The increase was predominately from $825,000 in SPT expenses recorded in the third quarter of 2018, as realized pricing was greater than US$50.00 in the quarter.

Year to date income tax expenses were $1,864,000 in the current year, reflecting an increase of $1,669,000 from the 2017 comparative period. SPT expenses contributed $1,544,000 of the variance based on increased year over year realized pricing. In addition, the Company accrued $103,000 in UL expense during the first nine months of 2018, as one Trinidad entity was estimated to be in a taxable UL position based on increased operating results and cash flows. Green fund levy expenses increased on a year to date basis in 2018 due to increases in petroleum sales from the prior year comparable period.

The September 30, 2018 income tax payable balance was comprised of the following:

($000's)	**Principal**	**Interest**	**Total**
Prior year (2017 and prior) taxes (receivable) payable	(127)	3,088	2,961
Current year (2018) tax accruals less instalments paid	922	-	922
Income taxes payable	**795**	**3,088**	**3,883**

Touchstone's $15,389,000 (December 31, 2017 - $10,280,000) deferred income tax liability balance represented the estimated future tax consequences attributable to differences between financial statement carrying amounts of assets and liabilities and their respective tax bases as at September 30, 2018. The deferred tax liability balance mainly related to the discrepancy of the tax values over the carrying values of the Company's producing assets. The primary driver of the increase from year-end 2017 was based on the extensive capital activity throughout 2018. Current year Trinidad capital allowances were deducted for PPT purposes at 50%, a greater rate than the carrying values of property and equipment which were reduced by depletion. During the three and nine months ended September 30, 2018, the Company recorded deferred tax expense of $1,401,000 and $4,722,000, respectively (2017 – $866,000 and $1,455,000).

At September 30, 2018, the Company had an estimated $29,844,000 and $2,245,000 in Trinidadian PPT and corporate tax losses, respectively (December 31, 2017 - $29,431,000 and $2,050,000). These may be carried forward indefinitely to reduce PPT and corporate taxes in future years. The benefit of $14,614,000 of Trinidad PPT and corporate tax losses were not recognized as at September 30, 2018 (December 31, 2017 - $12,957,000).

The Company previously acquired a Trinidad company that had overdue income tax balances owing to the Trinidad and Tobago Board of Inland Revenue ("BIR") which included both principal and interest components. The August 19, 2011 purchase and sales agreement related to the acquired subsidiary specified that upon confirmation from the BIR, the acquired subsidiary was responsible for the principal tax balances, and the seller was responsible for the tax interest balances. At the time of the acquisition, both parties intended to seek a waiver from the BIR for the tax interest, and the seller indemnified the acquired subsidiary with respect to the interest amounts. Subsequent to the acquisition date, the acquired subsidiary was responsible for interest on the principal balance until repaid. On October 9, 2012, the BIR accepted the acquired subsidiary's proposed settlement of the outstanding principal balances upon which the last payment was made in February 2013. As of September 30, 2018, $2,954,000 (December 31, 2017 - $2,853,000) in related interest was accrued in income taxes payable.

The acquired subsidiary has subsequently received BIR tax statements showing principal amounts and interest balances outstanding. The Company believes that the principal balance has been fully paid, and the full interest balance is the responsibility of the seller. During 2017, the seller was placed into joint liquidation. Management has received confirmation from external counsel that financial position of the seller and the Company's ability to recover funds under the indemnity remain unchanged. The Company continues to work with the BIR to resolve this matter and does not believe that it will be required to make any further income tax payments nor any payments for the seller's portion of any interest.

Cash, funds flow from operations and net earnings (loss)

($000's except for per share amounts)	Three months ended September 30, **2018**	2017	% change	Nine months ended September 30, **2018**	2017	% change
Cash provided (used) by operating activities	**1,000**	(814)	n/a	**6,139**	(1,900)	n/a
Funds flow from operations	**3,260**	1,387	100	**9,119**	2,218	100
Per share – basic(1)	**0.03**	0.01	100	**0.07**	0.02	100
Per share – diluted(1)	**0.02**	0.01	100	**0.07**	0.02	100
Net earnings (loss)	**267**	(1,203)	n/a	**(300)**	(4,600)	n/a
Per share – basic and diluted	**0.00**	(0.01)	n/a	**(0.00)**	(0.05)	n/a

Note:
(1) See "*Non-GAAP Measures*".

Cash provided by operating activities and funds flow from operations increased in the third quarter of 2018 when compared to the same period in 2017 as a result of stronger realized crude oil pricing and operating netback combined with a 22% increase in production. Touchstone recognized net earnings during the three months ended September 30, 2018 versus a net loss of $1,203,000 reported in the prior year third quarter. The annual increase was predominately due to increased operating netback, offset by increased current income taxes recorded in the current year.

Similarly, cash provided by operations and funds flow from operations increased in the first nine months of 2018 versus the equivalent period of 2017 based on increased operating netback achieved from stronger realized pricing and increased production. The Company reduced its net loss from $4,600,000 reported during the nine months ended September 30, 2017 to $300,000 in the same period of the current year, mainly from increased operating netback and decreased finance and foreign exchange expenses, partially offset by increased current and deferred income taxes recorded in the current year.

Capital Expenditures and Dispositions

Exploration asset expenditures

Exploration asset expenditures include asset additions in areas that have been determined to be in the exploration phase. The following table summarizes the Company's exploration asset expenditures during the respective periods:

($000's)	Three months ended September 30, **2018**	2017	% change	Nine months ended September 30, **2018**	2017	% change
Lease payments	**339**	188		**696**	842	
Geological	**215**	5		**492**	5	
Capitalized G&A	**24**	4		**55**	35	
Other	**-**	5		**(3)**	28	
Exploration asset expenditures	**578**	202	100	**1,240**	910	36

The Company spent $339,000 and $696,000 in head licence costs for the Ortoire and East Brighton properties during the three and nine months ended September 30, 2018, respectively. Geological costs of $215,000 and $492,000 and capitalized G&A of $24,000 and $55,000 were related to increased work performed on the Ortoire property during the three and nine months ended September 30, 2018, respectively. In 2018, the Company has identified seven potential drilling locations on individual prospects within the Ortoire concession along with four additional follow-up opportunities. Touchstone has received certificates of environmental compliance on four of the 11 locations and is proceeding with applications on the remaining prospects.

Property and equipment (development) expenditures

($000's)	**Three months ended September 30,**		% change	**Nine months ended September 30,**		% change
	2018	2017		**2018**	2017	
Drilling and completions	**4,154**	1,576		**11,736**	6,551	
Capitalized G&A	**295**	208		**846**	611	
Corporate assets / other	**94**	105		**102**	213	
Development expenditures	**4,543**	1,889	100	**12,684**	7,375	72

During the three months ended September 30, 2018, the Company incurred $4,154,000 in drilling and completion capital expenditures, as the Company drilled three wells and performed 12 well recompletions. In the 2017 comparative quarter, the Company drilled one well and recompleted three wells.

On a year to date basis, the Company incurred $11,736,000 in drilling and completion capital expenditures in 2018, which represented a total of eight new wells drilled and 21 well recompletions. During the nine months ended September 30, 2017, the Company drilled four wells and performed 13 well recompletions.

Property disposition

On June 21, 2018 the Company entered an agreement to dispose of its 50% operating working interest in the Icacos property to the current third-party partner for minimum consideration of US$500,000. The consideration will be paid based on the Company's working interest net revenue it would have received had it retained such interest through December 2021. Should these cumulative payments not exceed the minimum consideration, the Company will receive the difference prior to the end of February 2021. The Company shall retain all cumulative payments should such payments exceed the US$500,000 minimum consideration through December 31, 2021. The agreement was effective April 1, 2018 and remains subject to local regulatory approvals.

At September 30, 2018, the Company reclassified the $183,000 net carrying value of the related assets from property and equipment to assets held for sale. In addition, $80,000 of associated decommissioning obligations were classified as liabilities held for sale as at September 30, 2018.

Capital lease

The Company entered into a five-year, US$1,836,000 contractual agreement to lease its four service rigs and ancillary equipment to a third party on October 1, 2017. The lease arrangement also included the Company's coil tubing unit that was previously leased to the same party on May 1, 2015. The lease bears a fixed interest rate of 8% per annum, compounded and payable monthly. Principal payments commenced in January 2018, and the Company continues to hold title to the assets until all principal and associated interest payments have been collected.

The lease arrangement was accounted for as a finance lease, as substantially all of the risks and rewards of ownership are held by the lessee. The Company's finance lease receivable was $2,185,000, of which $1,421,000 was classified as long-term other assets as of September 30, 2018 (December 31, 2017 - $2,308,000 and $1,817,000, respectively).

Liquidity and Capital Resources

Touchstone exited the quarter with cash of $6,835,000, a working capital surplus of $2,025,000, and a $15,000,000 principal term loan balance. Touchstone's cash and working capital have decreased from December 31, 2017 based on the capital-intensive nature of its development activities. The investments have increased both production and funds flow from operations from the prior year, as net debt to trailing twelve-month funds flow from operations was 1.3 times as of September 30, 2018 versus 2.6 times as at December 31, 2017. Touchstone's $15,000,000 credit facility does not require principal payment until January 1, 2020, and the Company was well within the financial covenants as at September 30, 2018.

Touchstone's long-term goal is to fund current period capital expenditures and reclamation expenditures using only funds from operations. Profitable growth activities will be financed with a combination of funds flow from operations and other sources of capital. Stewardship of the Company's capital structure is managed through its financial and operating forecast process. The forecast of the Company's future cash flows is based on estimates of production, crude oil prices, capital expenditures, royalty expenses, operating expenses, general and administrative expenses and other investing and financing activities. The forecast is regularly updated based on changes in commodity prices, capital expenditures, production expectations and other factors that in the Company's view would impact cash flow.

Management's long-term objective objective is to maintain net debt to trailing twelve-month funds flow from operations at or below a level of 3.0 to 1. The Company also monitors its capital management through the net debt to net debt plus equity ratio. Management's strategy is to utilize more equity than debt, thereby targeting net debt to net debt plus shareholders' equity at a ratio of less than 0.4 to 1.

($000's)	**Target measure**	**September 30, 2018**	December 31, 2017
Working capital surplus(1)		**(2,025)**	(6,808)
Principal long-term portion of term loan		**15,000**	15,000
Net debt(2)		**12,975**	8,192
Shareholders' equity		**39,634**	38,204
Net debt plus equity		**52,609**	46,396
Trailing twelve-month funds flow from operations		**10,011**	3,110
Net debt to funds flow from operations	**< 3.0 times**	**1.3**	2.6
Net debt to net debt plus equity	**< 0.4 times**	**0.2**	0.2

Notes:
(1) Working capital surplus is a Non-GAAP measure and is calculated as current assets less current liabilities as they appear on the consolidated statements of financial position.
(2) See "*Non-GAAP Measures"*.

Term loan

On November 23, 2016, the Company completed an arrangement for a $15,000,000, five-year term credit facility from a Canadian investment fund. The term loan bears a fixed interest rate of 8% per annum, compounded and payable quarterly.

Effective June 15, 2018, the Company and the lender entered into a Second Amending Agreement to the Credit Agreement (the "Amendment"). The Amendment extended the term loan maturity date to November 23, 2022 and extended all principal payments by one year. The Company is required to repay $810,000 per quarter commencing on January 1, 2020 through October 1, 2022, and the then outstanding principal balance is repayable on the maturity date. In addition, the Amendment removed the minimum $5,000,000 quarterly cash reserves financial covenant. As consideration for the Amendment, the Company paid the lender a financing fee of $150,000.

Touchstone may prepay any principal portion of the term loan at any time after May 23, 2018 and if it does so will incur the following prepayment fees:

- from May 23, 2018 to November 23, 2018, a fee of 3% of the amount prepaid;
- from November 24, 2018 to November 23, 2019, a fee of 2% of the amount prepaid; and
- from November 24, 2019 to November 22, 2022, a fee of 1% of the amount prepaid.

In connection with the term loan, the Company has granted the lender a production payment equal to 1% of total petroleum sales from then current Company land holdings in Trinidad. In addition to the Amendment, the Company and the lender extended the production payment agreement to mature on October 31, 2022 regardless of any repayment or prepayment of the term loan. The term loan and the Company's obligations in respect of the production payment are principally secured by fixed and floating security interests over all present and after acquired assets of the Company and its subsidiaries.

The production payment liability is governed by a separate agreement between the parties. The payment is defined as 1% of total sale proceeds, which is defined as the gross proceeds from the sale of the aggregate gross production attributable to the Company's participating interest in all then current Trinidad blocks. The payment is calculated quarterly and payable 35 days subsequent to the end of each fiscal quarter. Touchstone has the option, concurrent with repayment of the term loan in full, to buyout the production payment obligation. The buyout shall be negotiated by both parties and calculated by the Company as prepared by reference to internal forecasts discounted at 8% per annum.

The debt instrument is comprised of two components: the term loan liability and the production payment liability. At inception the term loan liability was measured at fair value, net of all transaction fees, using a discount rate of 12%. The term loan was revalued based on the Amendment, resulting in a revaluation gain of $283,000 recognized during the nine months ended September 30, 2018 (2017 - $nil). The term loan balance less transaction costs is unwound using the effective interest rate method to the principal value at maturity with a corresponding non-cash accretion charge to net earnings.

The production payment liability was initially measured at fair value, based on internally estimated future production and pricing at the inception of the loan and a discount rate of 15%. The obligation is revalued at each reporting period based on updated future production and forward crude oil pricing forecasts. As a result of changes in future production and forward crude pricing estimates and the Amendment, a revaluation gain of $350,000 and a revaluation loss of $59,000 were recognized during the three and nine months ended September 30, 2018, respectively (2017 - $nil and $nil).

The following table is a continuity schedule of the term loan and associated liabilities for the specified periods:

($000's)	**Term loan liability**	**Royalty liability**	**Total**
Balance, January 1, 2017	**13,296**	**1,200**	**14,496**
Revaluation loss	-	166	166
Accretion	550	-	550
Payments	-	(319)	(319)
Balance, December 31, 2017	**13,846**	**1,047**	**14,893**
Revaluation (gain) loss	(283)	59	(224)
Accretion	300	-	300
Payments	(156)	(358)	(514)
Balance, September 30, 2018	**13,707**	**748**	**14,455**
Current	-	273	273
Non-current	13,707	475	14,182
Term loan and associated liabilities	**13,707**	**748**	**14,455**

The term loan arrangement contains industry standard representations and warranties, positive and negative covenants and events of default. The financial covenants and the Company's estimated position as at September 30, 2018 were as follows:

Covenant	Covenant threshold	Nine months ended September 30, 2018
Net funded debt to equity ratio(1)	< 0.50 times	**0.29 times**
Net funded debt to EBITDA ratio(2)	< 2.50 times	**0.61 times**

Notes:
(1) Net funded debt is defined as interest-bearing debt less cash reserves. Equity is defined as book value of shareholders' equity less accumulated other comprehensive income (loss).
(2) Means the ratio of net funded debt to EBITDA for the trailing twelve-month period. EBITDA is defined as net earnings before interest, income taxes and non-cash items.

Pursuant to the credit agreement, a failure of any covenant constitutes an event of default. Upon an event of default, the lender can declare the principal loan balance and any accrued interest immediately due and payable. The Company routinely reviews the term loan covenants based on actual and forecasted results and can make changes to development and exploration plans to comply with the covenants. The Company is committed to having an adaptable capital expenditure program that can be adjusted to a tightening of liquidity sources if necessary.

Restricted cash

As at September 30, 2018, the Company had cash collateralized bonds totaling US$271,000 ($350,000) related to its work commitments on its Petrotrin concessions (December 31, 2017 – US$299,000 and $376,000). The balance was classified as long-term restricted cash on the statement of financial position as the bonds expire at the expiration of the relevant licence agreement.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. The Company's approach to managing liquidity is to ensure that it will have sufficient liquidity to meet liabilities when due, under both normal and unusual conditions without incurring unacceptable losses or jeopardizing the Company's business objectives. The Company manages this risk by preparing cash flow forecasts to assess whether additional funds are required. The Company's liquidity is dependent on the Company's expected business growth and changes in its business environment.

To manage its capital structure in a period of low commodity prices, the Company may reduce its fixed cost structure, adjust capital spending, issue new equity or seek additional sources of debt financing. The Company will continue to manage its expenditures to reflect current financial resources in the interest of sustaining long-term viability. Undiscounted cash outflows relating to financial liabilities as at September 30, 2018 were as follows:

($000's)	Undiscounted amount	Less than 1 year	1 – 3 years	4 – 5 years
Accounts payable and accrued liabilities	15,288	15,288	-	-
Income taxes payable	3,883	3,883	-	-
Term loan principal	15,000	-	5,670	9,330
Term loan production payment liability	1,237	301	621	315
Financial liabilities	**35,408**	**19,472**	**6,291**	**9,645**

Risk Management

Management of cash flow variability is an integral component of Touchstone's business strategy. Changing business conditions are monitored regularly and, where material, reviewed with the Board of Directors to establish risk management guidelines used by Management to carry out the Company's strategic risk management program. The risk exposure inherent in the movements of the price of crude oil and fluctuations in Cdn$:US$, Cdn$:TT$ and US$:TT$ exchange rates are all proactively reviewed by Touchstone and may be managed through the use of derivative contracts as considered appropriate.

The Company has elected not to apply IFRS prescribed "hedge accounting" rules. Accordingly, the fair value of financial derivative contracts is recorded at each period-end. The fair value may change substantially from period to period depending on market conditions. As a result, net earnings may fluctuate considerably based on the period ending commodity forward strip prices compared to the prices in any derivative contracts.

Commodity price risk

The Company is exposed to commodity price movements as part of its operations. Commodity prices for oil are impacted by the world and continental/regional economy and other events that dictate the levels of supply and demand. Consequently, these changes could also affect the value of the Company's properties, the level of spending for exploration and development and the ability to meet obligations as they come due.

Touchstone maintains a risk management strategy to protect funds flow from operations from the volatility of commodity prices. Touchstone's strategy focuses on the use of puts, costless collars, swaps or fixed price contracts to limit exposure to fluctuations in commodity prices while allowing for participation in commodity price increases.

In January 2018, the Company entered into the following crude oil financial derivative contracts for total costs of US$153,000 ($190,000) to mitigate its exposure to fluctuations in commodity prices:

Oil contracts	Volume	Pricing point	Strike price	Term
Put options	500 barrels per day	Brent ICE	US$55.00 per barrel	March 1, 2018 to Dec. 31, 2018

The Company recognized the premium for the put options as a derivative financial asset. The derivatives are subsequently recorded at their estimated fair value based on the difference between the contracted price and the period-end forward price using quoted market prices. As at September 30, 2018, the Company recorded a financial derivative asset of $nil related to the put options (December 31, 2017 - $nil).

To further manage commodity price risk, the Company may reduce its fixed operating and administrative cost structure, reduce capital expenditures, issue new equity or seek additional sources of debt should forward commodity pricing materially decrease. The Company will continue to monitor forward commodity prices and may enter future commodity based risk management contracts to reduce the volatility of petroleum sales and protect future development capital programs.

Foreign currency risk

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of the Company's financial assets or liabilities. As the Company primarily operates in Trinidad, fluctuations in the exchange rate between the Canadian dollar and the TT$ can have a significant effect on reported results. Given that the TT$ is loosely pegged to the US$, the underlying risk is based on movements between the Canadian dollar and the US$ (see "*Foreign exchange and foreign currency translation*").

The Company's foreign currency policy is to monitor foreign currency risk exposure in its areas of operations and mitigate that risk where possible by matching foreign currency denominated expenses with revenues denominated in foreign currencies. The Company attempts to limit its exposure to foreign currency through collecting and paying foreign currency denominated balances in a timely fashion. The Company had no contracts in place to manage foreign currency risk as at or during the three and nine months ended September 30, 2018.

Interest rate risk

Interest rate risk arises from changes in market interest rates that may affect net earnings, cash flows and valuations. The Company is not exposed to interest rate risk as its term loan interest rate is fixed in nature.

Credit risk

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. The Company's crude oil production is sold, as determined by market-based prices adjusted for quality differentials, to Petrotrin. Typically, the Company's maximum credit exposure to Petrotrin is revenue for one month's petroleum sales, of which $6,309,000 was included in accounts receivable as at September 30, 2018 (December 31, 2017 - $2,196,000). The Company's carrying values of accounts receivable represented the Company's maximum credit exposure.

The aging of accounts receivable as at September 30, 2018 and December 31, 2017 were as follows:

	September 30, 2018	December 31, 2017
Not past due	**8,151**	3,388
Past due greater than 90 days	**5,809**	5,156
Accounts receivable	**13,960**	8,544

As at September 30, 2018, the Company determined that the average expected credit loss on the Company's accounts receivables was nil. The Company believes that the accounts receivable balances that are past due are ultimately collectible. The majority are due from the Trinidad government for value added taxes, and the Company has historically not experienced any collection issues.

Contractual Obligations, Commitments and Guarantees

In the normal course of operations, the Company executes agreements that provide for indemnification and guarantees to counterparties in transactions such as the sale of assets. The Company indemnifies its directors and officers against any and all claims or losses reasonably incurred in the performance of their services to the Company to the extent permitted by law. The Company maintains liability insurance for its officers and directors. The Company is party to various legal claims associated with the ordinary conduct of business, and the Company does not expect that these claims will have a material impact on its financial position.

The Company has minimum work obligations under various operating agreements with Petrotrin, exploration commitments under exploration licence and production agreements with the MEEI and various lease commitments for office space and equipment.

As at September 30, 2018, the Company's estimated contractual capital requirements were as follows:

($000's)	**Total**	**2018**	**2019**	**2020**	**Thereafter**
Operating agreement commitments					
Coora blocks	**40**	5	17	18	-
WD-4 block	**91**	9	40	42	-
WD-8 block	**85**	9	37	39	-
New Dome block	**52**	-	2	47	3
South Palo Seco block	**1,251**	412	541	161	137
Fyzabad block	**774**	9	36	39	690
Exploration agreement commitments					
Ortoire block	**10,917**	76	6,768	4,073	-
East Brighton block	**3,499**	95	402	3,002	-
Office leases	**1,021**	113	320	306	282
Equipment leases	**480**	79	221	176	4
Minimum payments	**18,210**	**807**	**8,384**	**7,903**	**1,116**

Under the terms of its operating agreements, the Company must fulfill the minimum work obligations on an annual basis over the specific licence term. In aggregate, the Company is obligated to drill 12 wells and perform 18 well recompletions prior to the end of 2021. As of the date of this MD&A, ten wells and 14 well recompletions have been completed with respect to these obligations (see "*Operating Agreements*"). The Company has provided US$271,000 in cash collateralized guarantees to Petrotrin to support its operating agreement work commitments (see "*Liquidity and Capital Resources - Restricted cash"*).

The Company's September 30, 2018 estimated costs and timing of its future Ortoire exploration commitments, which included acquiring and processing 85-line kilometres of 2D seismic and the drilling of four vertical wells, were as follows:

($000's)	**Total**	**2018**	**2019**	**2020**	**Thereafter**
Lease payments	**724**	76	317	331	-
2D seismic	**3,742**	-	-	3,742	-
Drilling commitments	**6,451**	-	6,451	-	-
Minimum payments	**10,917**	**76**	**6,768**	**4,073**	**-**

The Company's September 30, 2018 estimated costs and timing of its future East Brighton exploration commitments, which included the drilling of one well to a total depth of 5,000 true vertical feet, were as follows:

($000's)	**Total**	**2018**	**2019**	**2020**	**Thereafter**
Lease payments	**919**	95	402	422	-
Drilling commitments	**2,580**	-	-	2,580	-
Minimum payments	**3,499**	**95**	**402**	**3,002**	**-**

The Company has provided the MEEI with a US$2,150,000 guarantee in the form of a letter of credit to support exploration work commitments under its East Brighton block. Export Development Canada ("EDC") has provided a performance security guarantee to support the full value of the letter of credit issued by Touchstone. The letter of credit may be reduced from time to time to reflect any work performed on the block.

Off-balance Sheet Arrangements

Touchstone has certain equipment and office lease agreements reflected in the contractual obligations and commitments table above which were entered in the normal course of operations. All leases are currently treated as operating leases whereby the lease payments are included in operating expenses or G&A expenses depending on the nature of the lease. No asset or liability value has been assigned to these leases on the statement of financial position as of September 30, 2018.

As disclosed above, the Company has a US$2,150,000 letter of credit that is secured by EDC. This balance was not included on the statement of financial position as at September 30, 2018.

Financial Instruments

On January 1, 2018, as a result of the adoption of IFRS 9 *Financial Instruments* ("IFRS 9"), the Company changed the classification of its financial instruments as follows:

Financial Instrument	Measurement Category	
	Previous	**New (IFRS 9)**
Cash	Held-for-trading (FVTPL)	Amortized cost
Accounts receivable	Loans and receivables (amortized cost)	Amortized cost
Financial derivatives	Fair value through profit and loss ("FVTPL")	FVTPL
Restricted cash	Held-for-trading (FVTPL)	Amortized cost
Accounts payable and accrued liabilities	Other financial liabilities (amortized cost)	Amortized cost
Income taxes payable	Other financial liabilities (amortized cost)	Amortized cost
Term loan and associated liabilities	Other financial liabilities (amortized cost)	Amortized cost

The classification of cash and restricted cash were the only instruments with changes in their classification. There was no difference in the measurement of these instruments under IFRS 9 due to the short-term and liquid nature of these financial assets (see "*Changes in Accounting Policies*").

Changes in Accounting Policies

Adoption of new accounting policies

Effective January 1, 2018, the Company adopted IFRS 9 *Financial Instruments*, which replaced IAS 39 *Financial Instruments: Recognition and Measurement*. The adoption of IFRS 9 did not result in any adjustments to the measurement of financial instruments, and no adjustment to retained earnings was required.

Effective January 1, 2018, the Company adopted IFRS 15 *Revenue from Contracts with Customers* ("IFRS 15"). IFRS 15 established a comprehensive framework for determining whether, how much, and when revenue from contracts with customers is recognized. The adoption of IFRS 15 did not impact the timing or measurement of revenue, and no adjustment to retained earnings was required.

Further information regarding the adoption of new accounting policies is included in Note 3 "*Changes to Accounting Policies*" to the Company's September 30, 2018 unaudited interim consolidated financial statements.

Future changes in accounting policies

The Company will be required to adopt IFRS 16 *Leases* on January 1, 2019. Further information regarding future changes in accounting policies is included in Note 3 "*Changes to Accounting Policies*" to the Company's September 30, 2018 unaudited interim consolidated financial statements.

Share Information

The Company is authorized to issue an unlimited number of voting common shares without nominal or par value. The following table summarizes the outstanding common shares, share options and incentive share options as at the date of this MD&A, September 30, 2018 and December 31, 2017:

	November 13, 2018	September 30, 2018	December 31, 2017
Common shares outstanding	129,021,428	129,021,428	129,021,428
Share options outstanding	8,534,640	8,534,640	6,870,840
Incentive share options outstanding	15,000	15,000	15,000
Fully diluted common shares	**137,571,068**	**137,571,068**	**135,907,268**

Significant Accounting Judgments, Estimates and Assumptions

The preparation of financial statements in conformity with IFRS requires Management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, revenues and expenses. Actual results may differ from estimates, and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. Estimates and underlying assumptions are reviewed on an ongoing basis, and any revisions to accounting estimates are recognized in the period in which the estimates are revised.

There were no changes to the Company's significant judgments, estimates or assumptions used in applying accounting policies during the three and nine months ended September 30, 2018. Further details on the Company's significant accounting policies and significant accounting judgements, estimates and assumptions can be found in Note 5 "*Use of Estimates, Judgements and Assumptions*" to the December 31, 2017 audited consolidated financial statements.

Control Environment

The Company is required to comply with National Instrument 52-109 - *Certification of Disclosure in Issuers' Annual and Interim Filings*. The certification of interim filings for the interim period ended September 30, 2018 requires that the Company discloses in the interim MD&A any changes in Touchstone's internal controls over financial reporting ("ICFR") that occurred during the period that have materially affected, or are reasonably likely to materially affect, the Company's ICFR. The Company confirms that no such changes were made to ICFR or disclosure controls and procedures during the three months ended September 30, 2018.

ICFR is a process designed to provide reasonable assurance that all assets are safeguarded; transactions are appropriately authorized; and to facilitate the preparation of relevant, reliable and timely information. Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Furthermore, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Business Risks

For a full understanding of risks that affect the Company, the following should be read in conjunction with the Company's December 31, 2017 Annual Information Form dated March 26, 2018, which can be found on the Company's SEDAR profile (www.sedar.com).

The Company is exposed to a variety of risks including, but not limited to, operational, financial, competitive, political and environmental risks. As a participant in the oil and gas industry, the Company is exposed to a high level of exploration and production risk, upon which there is no assurance that hydrocarbon reserves will be discovered and economically produced. Operational risks include competition, reservoir performance uncertainties, well blow-outs and other operating hazards, lack of infrastructure or transportation to access markets and monetize reserves, and regulatory, environment and safety concerns. The Company works to mitigate these risks by employing highly skilled personnel and utilizing available technology. The Company also maintains a corporate insurance program consistent with industry practices to protect against insurable losses.

As noted in the "*Risk Management*" section of this MD&A, the Company is exposed to normal financial risks inherent in the oil and gas industry including commodity price risk, exchange rate risk, interest rate risk and credit risk. The Company continuously monitors opportunities to use financial instruments to manage exposure to fluctuations in foreign exchange and commodity prices. The Company operates the majority of its properties and, therefore, has significant control over the timing and costs related to exploration commitments and development opportunities. From time to time, the Company may have to raise additional funds to finance business development activities. The Company's ability to raise additional capital will depend on a number of factors such as general economic and market conditions that are beyond the Company's control.

The Company has the majority of its exploration and production agreements and all of its crude oil marketing agreements with Petrotrin, who is currently undergoing an extensive restructuring. In addition, Touchstone is operating under a number of expired licences. See "*Operating Agreements*" for a discussion of these risks.

Advisory on Forward-Looking Statements

Certain information regarding Touchstone set forth in this MD&A, including assessments by the Company's Management of the Company's plans and future operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "target", "intend", "could", "might", "should", "believe" and other similar expressions.

Such statements represent the Company's internal projections, estimates or beliefs concerning, among other things, future growth, results of operations, production rates, production decline rates, the magnitude of and ability to recover oil and gas reserves, plans for and results of drilling and recompletion activities, well abandonment costs, the ability to secure necessary personnel, equipment and services, environmental matters, future commodity prices, changes to prevailing regulatory, royalty, tax and environmental laws and regulations, the impact of competition, future capital and other expenditures (including the amount, nature and sources of funding thereof), future financing sources, business prospects and opportunities, risk that the Company will not be able to obtain contract extensions or fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its properties and risks related to lawsuits. Although the Company believes that the expectations reflected in the forward-looking statements are reasonable, it cannot guarantee future results, levels of activity, performance or achievement since such expectations are inherently subject to significant business, economic, operational, competitive, political and social uncertainties and contingencies. Many factors could cause the Company's actual results to differ materially from those expressed or implied in any forward-looking statements made by, or on behalf of, Touchstone.

In particular, forward-looking statements contained in this MD&A may include, but are not limited to, statements with respect to:

- the Company's business and operational strategies, including targeted jurisdictions and technologies used to execute its strategies;
- financial and business prospects and financial outlook;

- the Company’s future capital expenditure programs, including the anticipated timing, allocation and costs thereof and the method of funding;
- crude oil production levels and estimated field production levels;
- the performance characteristics of the Company's oil and natural gas properties;
- the quantity and estimated future net revenue from oil and natural gas reserves and the projections of market prices and costs;
- timing of and the Company’s ability to develop unproved reserves;
- expectations regarding the ability of the Company to raise capital and to continually add to reserves through acquisitions and development;
- future development and exploration activities to be undertaken in various areas and timing thereof, including the fulfillment of minimum work obligations and exploration commitments;
- terms and estimated future expenditures of the Company's contractual commitments and their timing of settlement;
- terms and title of exploration and production licences and the expected renewal of certain contracts;
- the Company’s expectations regarding its ability to obtain contract extensions or fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its undeveloped properties;
- Petrotrin’s current restructuring and the Company’s ability to maintain current exploration and production licences and marketing arrangements thereafter;
- receipt of anticipated or future regulatory approvals;
- expected levels of operating costs, general and administrative costs and other costs associated with the Company’s business;
- the Company's risk management strategy and the future use of commodity derivatives to manage movements in the price of crude oil;
- treatment under current and future governmental regulatory regimes and tax laws;
- tax horizon, royalty rates and future tax and royalty rates enacted in the Company’s areas of operations;
- the Company’s position related to its uncertain tax positions;
- foreign currency risk and the ability to reverse unrealized foreign exchange gains and losses in the future;
- the Company's future liquidity and future sources of liquidity;
- the Company’s future compliance with its term loan covenants;
- estimated amounts of the Company’s future production payments in connection with its term loan;
- the potential of future acquisitions or dispositions;
- general economic and political developments in Trinidad;
- estimated amounts, timing and the anticipated sources of funding for the Company's decommissioning obligations;
- effect of business and environmental risks on the Company; and
- the statements under “*Significant Accounting Judgments, Estimates and Assumptions*”.

Many factors could cause the Company's actual results to differ materially from those expressed or implied in any forward-looking statements made by, or on behalf of, the Company. The Company is exposed to numerous operational, technical, financial and regulatory risks and uncertainties, many of which are beyond its control and may significantly affect anticipated future results. The Company is exposed to risks associated with negotiating with foreign governments as well as country risk associated with conducting international activities. Operations may be unsuccessful or delayed as a result of competition for services, supplies and equipment, mechanical and technical difficulties, ability to attract and retain qualified employees on a cost-effective basis, commodity and marketing risk. The Company is subject to significant drilling risks and uncertainties including the ability to find crude oil reserves on an economic basis and the potential for technical problems that could lead to well blow-outs and environmental damage. The Company is exposed to risks relating to the inability to obtain timely regulatory approvals, surface access, access to third party gathering and processing facilities, transportation and other third party related operation risks. The Company is subject to industry conditions including changes in laws and regulations, the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced. There are uncertainties in estimating the Company's reserve base due to the complexities in estimated future production, costs and timing of expenses and future capital. The Company is subject to the risk that it will not be able to fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its properties. The financial risks the Company is exposed to include, but are not limited to, the impact of general economic conditions in Canada and Trinidad, continued volatility in market prices for crude oil, the impact of significant volatility in market prices for oil, the ability to access sufficient capital from internal and external sources, changes in income tax laws or changes in tax laws, royalties and incentive programs relating to the Trinidad oil and gas industry, fluctuations in interest rates, and fluctuations in foreign exchange rates. The Company is subject to local regulatory legislation, the compliance with which may require significant expenditures and non-compliance with which may result in fines, penalties or production restrictions or the termination of licence, exploration, lease operating or farm-in rights related to the Company's crude oil and gas interests in Trinidad. Readers are cautioned that the foregoing list of risk factors is not exhaustive. Additional information on these and other factors that could affect the Company'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).

Management has included the above summary of assumptions and risks related to forward-looking statements and other information provided in this MD&A in order to provide shareholders and investors with a more complete perspective on the Company's current and future operations, and such information may not be appropriate for other purposes. Actual results, performance or achievement could differ materially from that expressed in or implied by any forward-looking statements or information in this MD&A, and accordingly, investors should not place undue reliance on any such forward-looking statements or information. Further, any forward-looking statement or information speaks only as of the date on which such statement is made, and Touchstone undertakes no obligation to update any forward-looking statements or information to reflect information, events, results, circumstances or otherwise after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as required by law, including securities laws. All forward-looking statements and information contained in this MD&A and other documents of Touchstone are qualified by such cautionary statements. New factors emerge from time to time, and it is not possible for Management to predict all of such factors and to assess in advance the impact of each such factor on Touchstone's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

Non-GAAP Measures

The MD&A contains terms commonly used in the oil and natural gas industry, including funds flow from operations per share, operating netback and net debt. These terms do not have a standardized meaning under IFRS and may not be comparable to similar measures presented by other companies. Shareholders and investors are cautioned that these measures should not be construed as alternatives to cash provided by operating activities, net income, total liabilities, or other measures of financial performance as determined in accordance with GAAP. Management uses these non-GAAP measures for its own performance measurement and to provide stakeholders with measures to compare the Company's operations over time.

The Company calculates funds flow from operations per share by dividing funds flow from operations by the weighted average number of common shares outstanding during the applicable period.

The Company uses operating netback as a key performance indicator of field results. Operating netback is presented on an absolute and per barrel basis and is calculated by deducting royalties and operating expenses from petroleum sales. If applicable, the Company also discloses operating netback both prior to realized gains or losses on derivatives and after the impacts of derivatives are included. Realized gains or losses represent the portion of risk management contracts that have settled in cash during the period, and disclosing this impact provides Management and investors with transparent measures that reflect how the Company's risk management program can impact netback metrics. The Company considers operating netback to be a key measure as it demonstrates Touchstone's profitability relative to current commodity prices. This measurement assists Management and investors in evaluating operating results on a per barrel basis to analyze performance on a historical basis. The following table calculates operating netback for the periods indicated:

($000's unless otherwise indicated)	**Three months ended September 30,**		**Nine months ended September 30,**	
	2018	2017	**2018**	2017
Petroleum sales	**12,890**	7,885	**35,782**	22,712
Royalties	**(3,319)**	(1,929)	**(9,805)**	(6,297)
Operating expenses	**(3,567)**	(2,722)	**(9,349)**	(8,043)
Operating netback	**6,004**	3,234	**16,628**	8,372
Production *(bbls)*	**161,716**	132,199	**456,889**	368,794
Operating netback *($/bbl)*	**37.13**	24.46	**36.40**	22.70

The Company closely monitors its capital structure with a goal of maintaining a strong financial position in order to fund current operations and the future growth of the Company. The Company monitors working capital and net debt as part of its capital structure to assess its true debt and liquidity position and to manage capital and liquidity risk. Net debt is calculated by summing the Company's working capital and the principal (undiscounted) amount of long-term debt. Working capital is calculated as current assets less current liabilities as they appear on the statements of financial position. The following table summarizes net debt for the periods indicated:

($000's)	**September 30, 2018**	December 31, 2017	September 30, 2017
Current assets	**(21,549)**	(23,107)	(14,703)
Current liabilities	**19,524**	16,299	14,301
Principal long-term portion of term loan	**15,000**	15,000	15,000
Net debt	**12,975**	8,192	14,598

Summary of Quarterly Results

The following is a summary of the unaudited quarterly results of the Company for the eight most recently completed fiscal quarters:

Three months ended	September 30, 2018	June 30, 2018	March 31, 2018	December 31, 2017
Operating				
Average daily production *(bbls/d)*	1,758	1,717	1,543	1,448
Net wells drilled	3	3	2	-
Net wells recompleted	12	4	5	7
Brent benchmark price(1) *(US$/bbl)*	75.10	74.53	66.86	61.45
Operating netback(2) *($/bbl)*	37.13	38.19	33.53	22.14
Financial *($000's except share and per share amounts)*				
Petroleum sales	12,890	12,508	10,384	9,308
Funds flow from operations	3,260	3,258	2,601	892
Per share – basic(2)	0.03	0.03	0.02	0.01
Per share – diluted(2)	0.02	0.03	0.02	0.01
Net earnings (loss)	267	(692)	125	3,653
Per share – basic and diluted	0.00	(0.01)	0.00	0.03
Capital expenditures				
Exploration	578	434	228	330
Development	4,543	4,520	3,621	763
	5,121	4,954	3,849	1,093
Net debt(2) – end of period				
Working capital surplus	(2,025)	(3,734)	(4,922)	(6,808)
Principal long-term balance of term loan	15,000	15,000	14,190	15,000
	12,975	11,266	9,268	8,192
Weighted average shares outstanding				
Basic	129,021,428	129,021,428	129,021,428	105,955,000
Diluted	130,728,340	129,021,428	129,691,693	106,542,151
Outstanding shares - end of period	129,021,428	129,021,428	129,021,428	129,021,428

Notes:
(1) Average for the quarterly periods indicated. Source: US Energy Information Administration.
(2) See "*Non-GAAP Measures*".

Three months ended	September 30, 2017	June 30, 2017	March 31, 2017	December 31, 2016
Operating				
Average daily production *(bbls/d)*	1,437	1,334	1,280	1,245
Net wells drilled	1	3	-	-
Net wells recompleted	3	5	5	8
Brent benchmark price[(1)] *(US$/bbl)*	52.10	49.55	53.59	49.11
Operating netback[(2)] *($/bbl)*	24.46	19.88	23.66	23.40
Financial *($000's except share and per share amounts)*				
Petroleum sales	7,885	7,436	7,391	7,084
Funds flow from operations	1,387	438	393	353
Per share – basic and diluted[(2)]	0.01	0.01	0.01	0.01
Net loss	(1,203)	(1,848)	(1,549)	(7,154)
Per share – basic and diluted	(0.01)	(0.02)	(0.02)	(0.09)
Capital expenditures				
Exploration	202	520	188	553
Development	1,889	4,940	546	819
	2,091	5,460	734	1,372
Net debt[(2)] – end of period				
Working capital surplus	(402)	(1,186)	(5,584)	(846)
Principal long-term balance of term loan	15,000	15,000	15,000	15,000
	14,598	13,814	9,416	14,154
Weighted average shares outstanding				
Basic and diluted	103,137,143	84,236,044	83,137,143	83,137,143
Outstanding shares - end of period	103,137,143	103,137,143	83,187,143	83,187,143

Notes:
(1) Average for the quarterly periods indicated. Source: US Energy Information Administration.
(2) See "*Non-GAAP Measures*".

The Company's petroleum sales and funds flow from operations are significantly impacted by changes in production volumes and fluctuations in commodity prices. In addition, net earnings and total asset values are impacted by exploration asset and development property and equipment impairments and reversals.

In response to the decrease in crude oil prices, the Company decreased 2016 and first quarter 2017 capital and operational spending, which reduced crude oil production and operating cash flows.

Currency and References to Touchstone

All information included in this MD&A is shown on a Canadian dollar basis unless otherwise stated. Tabular amounts herein are in thousands of Canadian dollars, and the amounts in text are rounded to thousands of Canadian dollars. For convenience, references in this document to the "Company", "we", "us", "our", and "its" may, where applicable, refer only to Touchstone.

Additional Information

Additional information regarding Touchstone Exploration Inc., including Touchstone's Annual Information Form, can be accessed online on SEDAR at www.sedar.com or from the Company's website at www.touchstoneexploration.com.

CORPORATE INFORMATION

DIRECTORS

John D. Wright
Chairman of the Board

Paul R. Baay

Kenneth R. McKinnon

Peter Nicol

Stanley T. Smith

Thomas E. Valentine

Harrie Vredenburg

EXECUTIVE OFFICERS

Paul R. Baay
President and Chief Executive Officer

Scott Budau
Chief Financial Officer

James Shipka
Chief Operating Officer

STOCK EXCHANGE LISTING

Toronto Stock Exchange
London Stock Exchange AIM
Symbol: TXP

HEAD OFFICE

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T2P 3N9

OPERATING OFFICE

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Port of Spain, Trinidad

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Calgary, Alberta

LEGAL COUNSEL

Norton Rose Fulbright LLP
Calgary, Alberta
London, United Kingdom

Nunez and Co.
Port of Spain, Trinidad

TRANSFER AGENT AND REGISTRAR

Computershare Trust Company of Canada
Calgary, Alberta

NOMINATED ADVISOR AND JOINT BROKER

Shore Capital
London, United Kingdom

JOINT BROKER

GMP FirstEnergy
London, United Kingdom

PUBLIC RELATIONS

Camarco
London, United Kingdom

ABBREVIATIONS

The following is a list of abbreviations that may be used in this MD&A:

Oil

bbls	barrels
Mbbl	thousand barrels
bbls/d	barrels per day
Brent	The reference price paid for crude oil FOB North Sea
WTI	Western Texas Intermediate, the reference price paid for crude oil and standard grade in U.S. dollars at Cushing, Oklahoma

Other

AIM	AIM market of the London Stock Exchange plc
Cdn$	Canadian dollar
TSX	Toronto Stock Exchange
TT$	Trinidad and Tobago dollar
US$	United States dollar