Touchstone Exploration Inc.
(formerly Petrobank Energy and Resources Ltd.)

Management's Discussion and Analysis

December 31, 2015

The following Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of Touchstone Exploration Inc. (formerly Petrobank Energy and Resources Ltd.) (the "Company" or "Touchstone") for the year ended December 31, 2015, with comparisons to the year ended December 31, 2014 is dated March 24, 2016 and should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2015 and 2014. 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.

Additional information related to Touchstone and factors that could affect the Company's operations and financial results will be included in the Company's Annual Information Form, which will be filed on or before March 30, 2016, and may be accessed through the SEDAR website at www.sedar.com.

Tabular amounts herein are in thousands of Canadian dollars, and the amounts in text are rounded to thousands of Canadian dollars unless otherwise stated. All production volumes disclosed herein are sales volumes. Certain prior year amounts have been reclassified to conform to current year presentation. Refer to the end of this MD&A for commonly used abbreviations in the document. Refer to end of this document for the Advisory on Reserves Information, Advisory on Forward-Looking Statements, and for Non-GAAP Measures and abbreviations used in this MD&A.

On May 13, 2014, the Company completed a plan of arrangement with Touchstone Exploration Inc. (now Touchstone Energy Inc., a wholly-owned subsidiary of Touchstone) ("Old Touchstone"). Petrobank Energy and Resources Ltd. was the acquirer, and as such, comparative results prior to May 14, 2014 do not include the results of operations from Old Touchstone. All current and comparative share capital and per share amounts were adjusted to reflect the two for one common share consolidation completed on May 13, 2014. During the three months ended June 30, 2015, the Company received new information which revised the original accrued liabilities estimate in the preliminary purchase price allocation. This resulted in an increase in accounts payable and accrued liabilities of $477,000 and a corresponding increase to property and equipment. The final purchase price allocation was revised to reflect this amount. As the related Trinidad cash generating unit property and equipment balances were impaired on December 31, 2014, an impairment charge of $477,000 was recognized in the 2014 consolidated statement of earnings. All comparative amounts were restated accordingly.

On July 1, 2014, the Company determined that the Kerrobert and Luseland producing properties met the criteria for technical feasibility and commercial viability. As of July 1, 2014 all associated revenues, royalties and operating expenses of the two Canadian cash generating units have been recognized in the consolidated statement of earnings (prior to July 1, 2014, all revenues and costs were capitalized to exploration assets). Prior to its July 2015 disposition, Dawson operating results were capitalized to exploration assets as the property was in the exploration stage. Therefore, it is important to note that throughout this MD&A, operational results such as revenue, royalties, and production expenses related to the Dawson property and Kerrobert and Luseland properties prior to July 1, 2014 may be referenced but are capitalized for financial reporting purposes and thus do not appear in the consolidated statements of earnings.

Company Profile

The Company 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"). The Company's common shares are traded on the Toronto Stock Exchange under the symbol "TXP". The Company's strategy is to leverage western Canadian enhanced oil recovery experience and capability to international onshore properties to create shareholder value. Jurisdictions will be targeted that have stable political and fiscal regimes coupled with large defined original oil in place.

2015 Annual Highlights

- Achieved average oil sales of 1,756 bbls/d, 1,600 bbls/d produced in Trinidad and 156 bbls/d produced in Canada. Trinidad production increased 40% from the prior year while Canadian production decreased 61% from 2014.
- Realized Trinidad operating netbacks of $16,272,000 ($27.88 per barrel) which offset Canadian operating netback losses of $1,475,000 ($25.88 per barrel). Company operating netbacks were $14,797,000 or $23.09 per barrel, which represented a decrease of 2% from the prior year.
- Reduced annual per barrel operating expenses by 16% or $4.85 per barrel from 2014. Trinidad operating costs reduced by approximately US$4.97 per barrel or 22% from the previous year.
- Generated positive corporate funds flow from operations of $2,908,000 ($0.04 per basic share) compared to $390,000 ($0.01 per basic share) in 2014. Trinidad operations generated funds flow from operations of $7,157,000, offsetting Canadian funds flow losses of $4,249,000 recognized in 2015.
- Recorded a net loss of $22,147,000 ($0.27 per basic share), which was primarily driven by non-cash property and equipment impairment charges mainly associated with the decrease in forward commodity prices.
- Disposed of various non-core Canadian assets for combined cash proceeds of $8,500,000.
- Reduced net debt by $7,913,000 from the prior year, as the Company exited 2015 with a net surplus of $987,000.
- Entered into various ICE Brent referenced financial swaps for 800 bbls/d at an average price of US$63.25 for the 2016 year.
- Released an updated independently evaluated reserves assessment prepared by GLJ Petroleum Consultants Ltd. with proved plus probable reserves growth of 5% over 2014, increasing to 15,465 Mbbls and achieving a 219% reserve replacement ratio with total 2015 gross reserve additions of 679 Mbbls.
- Achieved Trinidad based proved plus probable reserves finding and development costs of $5.83 per barrel including future development capital.
- On February 1, 2016, disposed of the Kerrobert property and various undeveloped land rights for cash proceeds of $650,000. Through the disposition, the Company immediately eliminated operating losses and transferred its estimated Canadian discounted decommissioning liability balance of $4,028,000 to the purchaser effective December 31, 2015.

Annual Financial and Operating Results

	Year ended December 31, 2015	2014[1]
Operating		
Average daily oil production *(bbls/day)*		
Trinidad	**1,600**	1,146
Canada	**156**	404[2]
Company total	**1,756**	1,550[2]
Average realized oil prices before derivatives *($/bbl)*		
Trinidad	**58.45**	89.93
Canada	**38.80**	73.75[2]
Company total	**56.70**	85.71[2]
Trinidad operating netback[3] *($/bbl)*		
Reference price – Brent	**66.62**	109.04
Petroleum revenue	**58.45**	89.93
Royalties	**(18.35)**	(29.15)
Net revenue	**40.10**	60.78
Realized gain on derivatives	**10.59**	0.53
Operating costs	**(22.81)**	(27.57)
Operating netback	**27.88**	33.74
Canada operating netback[3] *($/bbl)*		
Reference price – WTI	**61.95**	102.71
Petroleum revenue	**38.80**	69.64
Royalties	**(6.93)**	(5.60)
Net revenue	**31.87**	64.04
Operating costs	**(57.75)**	(49.59)
Operating netback	**(25.88)**	14.45
Financial *($000's except share and per share amounts)*		
Funds flow from operations[3]		
Trinidad	**7,157**	8,901
Canada	**(4,249)**	(8,511)
Company total	**2,908**	390
Per share – basic and diluted[3,4]	**0.04**	0.01
Net loss	**(22,147)**	(57,262)
Per share – basic and diluted[4]	**(0.27)**	(0.82)
Capital expenditures		
Exploration assets	**1,245**	11,355
Property and equipment	**3,572**	23,610
Company total	**4,817**	34,965
Total assets – end of period	**100,619**	140,333
Net (surplus) debt[3] – end of period	**(987)**	6,926
Weighted average shares outstanding[4]		
Basic and diluted	**83,080,417**	70,245,489
Outstanding shares[4] - end of period	**83,087,143**	83,059,643

[1]Canadian 2014 results only include results for the six months ended December 31, 2014 as all properties were in the exploration stage prior to July 1, 2014. Trinidad comparative results are subsequent to the May 13, 2014 acquisition date.
[2]Average daily production and average realized prices include Canadian exploration property results.
[3]See "*Non-GAAP Measures.*"
[4] All current and comparative share amounts have been adjusted to reflect the two for one common share consolidation completed on May 13, 2014.

Throughout 2015, Touchstone focused on operational initiatives to ensure the sustainability and future profitability of the Company through all commodity cycles. As a result, production volumes in Trinidad declined based on reduced operating and capital investment. Touchstone remains focused on developing our core Trinidad resources, as we completed or recompleted 28 wells in 2015. Despite a decrease in realized oil prices and production, we exited 2015 with a year-end net surplus position of $987,000. The decrease in net debt from the prior year was primarily based on three Canadian asset dispositions that closed in 2015 for total cash proceeds of $8,500,000.

Production volumes averaged 1,756 bbls/d during the year December 31, 2015 (100% oil). Trinidad and Canadian petroleum sales averaged 1,600 bbls/d and 156 bbls/d, respectively, representing a combined increase of 13% from 2014. Touchstone responded to the continued weakness in oil prices by decreasing capital spending to $4,817,000 in 2015 from $34,965,000 in 2014. The 2015 expenditures were mainly on Trinidad based recompletions and exploration costs and represented a decrease of 86% from prior year capital spending.

Funds flow from operations for the year ended December 31, 2015 was $2,908,000 ($0.04 per basic share) versus funds flow from operations of $390,000 ($0.01 per basic share) recognized in the prior year. Funds flow increased from 2014 due to a full year of Trinidad operations and decreased Canadian based operating losses. Due to $38,142,000 in non-cash impairments, we recorded a net loss of $22,147,000 ($0.27 per basic share) during the year ended December 31, 2015. The impairment charges, mainly attributed to all Trinidad producing properties, was the result of sustained declines in forecasted short and long-term crude oil pricing.

As of the date of this MD&A, Touchstone's bank loan borrowing base is US$9,000,000, of which US$6,000,000 is dedicated to a letter of credit, US$2,000,000 is drawn and US$1,000,000 is currently available. The interim reductions to the borrowing base subsequent to December 31, 2015 are subject to a semi-annual borrowing base redetermination scheduled on April 1, 2016, which will incorporate the Company's December 31, 2015 independent reserves evaluation. There can be no certainty as to the ability of the Company to successfully restructure its credit facility or obtain new financing should low crude oil prices persist. The Company will continue to assess new sources of financing available and to manage its expenditures to reflect current financial resources in the interest of sustaining long-term viability.

2016 Outlook

Touchstone will continue to apply a prudent approach to capital expenditures, as we remain focused on cash flow preservation and balance sheet flexibility. Touchstone will not proceed with capital expenditures that have no immediate economic value at current price levels. We continue to have significant future growth potential with shut-in production and a large inventory of low risk development locations, but a majority of that potential will continue to be deferred until oil prices rebound. Touchstone's 2016 work obligations include the drilling of five development wells on our Trinidad concessions. We have restricted discretion over the timing of these commitments, and will schedule these operations as permitted by the terms of our Trinidad operating agreements.

Building on operating and general and administrative cost reductions achieved in 2015, we are continuing to actively pursue cost reductions to our fixed cost base. Subsequent to December 31, 2015, we closed the sale of our Kerrobert facility, which immediately eliminated operating losses and will allow for future general and administrative cost reductions.

Terminated Trinidad Asset Acquisition

On March 14, 2016, Touchstone and the seller terminated an October 16, 2015 agreement to purchase certain Trinidad onshore producing assets for cash consideration of US$20,800,000. The agreement was terminated as the seller was unable to satisfy the required conditions precedent prior to the backstop date. Accordingly, the $2,847,000 (US$2,080,000) deposit included in current assets as at December 31, 2015 was refunded to the Company and applied to its bank loan balance in March 2016.

Reserves

The Company engaged GLJ Petroleum Consultants Ltd. ("GLJ") to provide an evaluation of the Company's proved and probable reserves as at December 31, 2015. The reserves estimates set forth below were based upon GLJ's reserve report dated March 8, 2016. The reserves estimates were prepared in accordance with definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook and National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("NI – 51-101").

The reserve estimates represent Touchstone's gross working interest reserves, which are the Company's interest before the deduction of royalties. Reserve estimates are based on forecast prices and costs at December 31, 2015. The recovery and reserve estimations of the Company's crude oil reserves provided herein are estimates only, and there is no guarantee that the estimated reserves will be recovered. Actual crude oil reserves may be greater than or less than the estimates provided herein. Full disclosure with respect to the Company's reserves as at December 31, 2015 will be included in the Company's Annual Information Form, which will be filed on or before March 30, 2016 and may be accessed through SEDAR.

At the effective date of the reserves evaluation, Touchstone has divested all non-core Canadian developed and undeveloped assets with associated reserves as reported in the December 31, 2014 reserves evaluation. As a result, total proved plus probable reserves decreased by 2,989 Mboe, total proved reserves decreased by 1,479 Mboe, total proved plus probable undiscounted future development costs decreased $42.4 million and total proved undiscounted future development costs decreased $24.8 million. The reserves tables below provide a summary of the Company's Trinidad crude oil reserves at December 31, 2015.

December 31, 2015 Reserves

	Light and Medium Oil *(Mbbls)*	Heavy Oil *(Mbbls)*	Total Oil Equivalent *(Mboe)*
Proved			
Proved producing	4,188	702	4,890
Proved non-producing	413	90	503
Proved undeveloped	2,889	533	3,422
Total proved[1]	**7,490**	**1,325**	**8,815**
Probable	5,705	946	6,650
Total proved plus probable[1]	**13,195**	**2,271**	**15,465**

[1]Amounts may not add due to rounding.

Reserves Reconciliation

	Trinidad		Canada	
	Proved *(Mboe)*	Proved Plus Probable *(Mboe)*	Proved *(Mboe)*	Proved Plus Probable *(Mboe)*
December 31, 2014	**8,962**	**14,786**	**1,536**	**3,046**
Extensions and improved recovery	396	1,593	-	-
Technical revisions	215	(104)	-	-
Dispositions	-	-	(1,479)	(2,989)
Economic factors	(184)	(237)	-	-
Production	(573)	(573)	(57)	(57)
December 31, 2015[1]	**8,815**	**15,465**	**-**	**-**
Reserves replacement ratio[2] *(%)*	**75**	**219**	**n/a**	**n/a**

[1]Amounts may not add due to rounding.
[2]See "*Advisory on Reserves Information.*"

Principal Properties

Effective December 31, 2015, the Company’s principal land holdings were as follows:

Property	Working interest	Lease type	Gross acres	Working interest acres
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	2,019	2,019
Barrackpore	100%	Freehold	478	478
Fyzabad	100%	Crown & Freehold	804	804
Icacos	50%	Freehold	1,960	980
Palo Seco	100%	Crown	500	500
San Francique	100%	Freehold	2,306	2,306
Exploratory				
Bovallius	100%	Freehold	976	976
Cory Moruga	16%	Freehold	11,969	1,939
Moruga	100%	Freehold	3,300	3,300
New Grant	100%	Freehold	687	687
Ortoire	80%	Crown	44,731	35,785
Otaheite	100%	Freehold	935	935
Piparo	100%	Freehold	72	72
Rousillac	100%	Freehold	570	570
Siparia	50%	Freehold	160	80
St. John	100%	Freehold	408	408
	73%		**74,993**	**54,957**
Canada				
Beadle	100%	Freehold	4,798	4,798
Druid	100%	Crown	8,641	8,641
Luseland	100%	Crown & Freehold	6,849	6,849
Winter	100%	Crown	11,323	11,323
	100%		**31,611**	**31,611**
Company total	**81%**		**106,604**	**86,568**

The Company's core producing properties are located onshore within Trinidad. All properties are operated by Touchstone with the exception of the Cory Moruga exploration block.

The Company’s East Brighton offshore property is excluded in the table above as it was held for sale as of December 31, 2015.

On February 1, 2016, the Company closed a transaction to dispose of its Kerrobert facility and associated mineral rights, as well as undeveloped acreages in Edam, Luseland and Unity. The transaction was effective December 31, 2015 and therefore excluded from the table above.

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

The Company's LOAs initially expire on December 31, 2020, with Touchstone holding a five year renewal option. Under these agreements, the Company is subject to five year minimum work commitments (see the "*Contractual Obligations, Commitments and Guarantees*" section for further details) and annual minimum production covenants. The Company did not achieve its 2015 minimum production level covenant specified in the WD-8 LOA. However, a breach of the minimum production level covenant does not constitute a default provided the minimum work obligations have been completed. There were no additional repercussions, restrictions or other financial or operating impacts resulting from the WD-8 production covenant breach as all work commitments were met for the 2011 to 2015 period. As at December 31, 2015 and as of the date of this MD&A, the Company is in compliance with all other covenants associated with its LOAs.

The Company's farmout agreements initially expire on December 31, 2021. The Company holds a five year renewal option, and the agreements are subject to five year minimum work commitments. As at December 31, 2015 and as of the date of this MD&A, the Company is compliance with all covenants associated with its farmout agreements.

The Company's Fyzabad and Palo Seco agreements with the MEEI contain no major covenants but expired on August 19, 2013. The Company is currently negotiating license renewals and has permission from the MEEI to operate in the interim period. The Company has no indication that the two licenses will not be renewed. During the year ended December 31, 2015, the production volumes produced under expired MEEI production licenses represented 5.9% of total Trinidad segment production (2014 – 6.7%).

The Company is operating under a number of Trinidad freehold lease agreements which have expired and are currently being renegotiated. Based on legal opinions received, the Company is continuing to recognize revenue on the producing blocks as the Company is the operator, no title to the revenue has been disputed and the Company is paying all associated royalties and taxes. The Company currently has no indication that any of the producing expired leases will not be renewed. During the year ended December 31, 2015, the production volumes produced under expired Trinidad freehold lease agreements represented 2.2% of total Trinidad segment production (2014 – 4.9%).

Summary of Financial and Operating Results

The Company's operations are conducted in Trinidad and Canada, which are the Company's reportable segments.

Prior to its July 2015 disposition, the Company's Dawson property was in the exploration phase and accordingly, all directly attributable expenses net of revenues were capitalized as exploration assets. Prior to July 1, 2014, the Company's Kerrobert and Luseland properties were also in the exploration phase.

Production volumes

	2015	2014	% change
Trinidad			
Total oil production (bbls)	**583,929**	418,368	40
Average daily oil production (bbls/day)	**1,600**	1,146	40
Canada			
Total oil production (bbls)	**57,007**	147,477	(61)
Average daily oil production (bbls/d)	**156**	404	(61)
Company total			
Total oil production (bbls)	**640,936**	565,845	13
Average daily oil production (bbls/day)	**1,756**	1,550	13

Production volumes by property

(bbls)	**2015**	2014	% change
Trinidad			
Coora 1	**72,261**	59,733	21
Coora 2	**42,970**	29,580	45
WD-4	**205,243**	124,336	65
WD-8	**125,590**	106,421	18
New Dome	**5,603**	4,147	35
South Palo Seco	**2,867**	1,748	64
Barrackpore	**24,627**	12,783	93
Fyzabad	**71,013**	51,471	38
Icacos	**4,579**	3,005	52
Palo Seco	**6,718**	7,633	(12)
San Francique	**22,458**	17,511	28
	583,929	418,368	40
Canada			
Kerrobert	**53,967**	124,547	(57)
Luseland	**3,040**	17,143	(82)
Dawson	**-**	5,787	(100)
	57,007	147,477	(61)
Company total	**640,936**	565,845	13

Trinidad production increased 40% from the prior year as the Company acquired its Trinidad operations effective May 13, 2014. Subsequent to the acquisition, Trinidad production decreased 11% annually from 1,803 bbls/d in 2014 to 1,600 bbls/d in 2015. This decrease was a result of minimal capital investment in 2015, as no wells were drilled and twenty-eight recompletions were performed in Trinidad.

Canadian production decreased 61% from 2014 as Kerrobert production declined 57% based on the Company's concerted effort to reduce operating costs and invest minimal capital throughout 2015. In addition, Luseland operations were sold effective March 1, 2015, and the Dawson cyclical steam pilot project was terminated in October 2014 and disposed of in July 2015.

Average reference and realized prices

	Year ended December 31, 2015	2014	% change
Reference prices			
Brent average (US$/bbl)	**52.29**	98.97	(47)
Brent average (C$/bbl)[2]	**66.62**	109.04	(39)
WTI average (US$/bbl)	**48.63**	93.22	(48)
WTI average (C$/bbl)[2]	**61.95**	102.71	(40)
WCS average (US$/bbl)	**35.28**	73.60	(52)
WCS average (C$/bbl)[2]	**44.81**	81.10	(45)
Average realized selling prices, excluding derivatives ($/bbl)			
Trinidad	**58.45**	89.93	(35)
Canada	**38.80**	73.75[1]	(47)
Company total	**56.70**	85.71[1]	(34)
Trinidad			
Realized price discount as a % of Brent	**12**	18	(30)
Realized price discount as a % of WTI	**6**	12	(55)
Canada			
Realized price discount as a % of WTI	**37**	28	33
Realized price discount as a % of WCS	**13**	9	48

[1]Average realized prices include Canadian exploration property petroleum revenue.
[2]Canadian reference prices are calculated using the Bank of Canada C$/US$ noon day average on a daily basis.

Petroleum revenue

($000's)	Year ended December 31, 2015	2014[1]	% change
Trinidad			
Crude oil	**34,128**	37,624	(9)
Canada			
Crude oil	**2,212**	4,946	(55)
Company total	**36,340**	42,570	(15)

[1]Canadian 2014 results only include results for the six months ended December 31, 2014 as all properties were in the exploration stage prior to July 1, 2014. Trinidad comparative results are subsequent to the May 13, 2014 acquisition date.

Trinidad petroleum revenue was $34,128,000 during the year ended December 31, 2015, representing an average realized price of $58.45 per barrel. The average realized price represented a 12% discount to average Brent prices and a 6% discount to average WTI prices. This represented a decrease of 9% from May 14, 2014 to December 31, 2014 revenue, as the 40% production increase did not offset the 35% decline in average realized prices.

Over the past three years, realized Trinidad crude oil prices have consistently averaged a 12% discount to Brent average pricing. The Company sells all of its crude oil to Petrotrin, whom establishes a monthly net price for Trinidad oil. This price is adjusted for actual API by using a fixed API differential. A nominal transportation charge is also deducted from the monthly net price.

The Company enters into Trinidad based financial derivative contracts for the purposes of protecting funds flow from operations from the volatility of commodity prices. During the year ended December 31, 2015, the Company realized a gain on financial derivatives of $6,181,000 or $10.59 per barrel. The Company began using derivative contracts in December 2014, which resulted in a realized gain of $223,000 recorded during the year ended December 31, 2014. For further information, refer to the *"Risk Management"* section of this MD&A.

Canadian petroleum revenue for the year ended December 31, 2015 was $2,212,000, representing an average realized price of $38.80 per barrel. The decrease in Canadian petroleum revenues from the prior year was a result of the 61% decline in production combined with a 47% decrease in average realized prices.

As at December 31, 2015, Trinidad crude oil inventory totaled 8,019 barrels versus 10,608 barrels at December 31, 2014. The Company's crude oil is typically sold from its various sales batteries to Petrotrin three days per week. Crude oil sales are sold FOB shipping point, as the Company's sales batteries are directly tied into Petrotrin pipelines.

Royalties

($000's)	**Year ended December 31, 2015**	2014[1]	% change
Trinidad			
Crown royalties	**3,748**	4,282	
Private royalties	**739**	637	
Overriding royalties	**5,086**	6,543	
User fees	**1,142**	735	
	10,715	12,197	(12)
Percentage of petroleum revenue	**31.4%**	32.4%	(3)
Canada			
Crown royalties	**163**	21	
Overriding royalties	**232**	377	
	395	398	(1)
Percentage of petroleum revenue	**17.9%**	8.0%	100
Company total	**11,110**	12,595	(12)
Percentage of petroleum revenue	**30.6%**	29.6%	3

[1]Canadian 2014 results only include results for the six months ended December 31, 2014 as all properties were in the exploration stage prior to July 1, 2014. Trinidad comparative results are subsequent to the May 13, 2014 acquisition date.

Trinidad charges a crown royalty rate of 12.5% on gross production under crown leases. For freehold or private leases, the Company incurs private royalties between 10% and 12.5% of gross revenue. 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 33% to 35% on predefined base production levels. For any production volumes sold in excess of the base production levels, the Company incurs an enhanced NORR ("enhanced NORR") of 17.5% 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 are subject to farmout agreements that stipulate NORR rates ranging from 23% to 25% and enhanced NORR rates ranging from 15% to 17%. There are no incentives for drilling under the farmout agreements. Production from the WD-8, Coora and WD-4 blocks incur a TT$12.60 per barrel charge for user fees that serve to offset expenses for electricity, maintenance, labour and other miscellaneous costs incurred by Petrotrin associated with the management of the applicable lease operatorship programs.

Trinidad royalties were $10,715,000 for the year ended December 31, 2015, representing 31.4% of petroleum revenue. These royalty rates were in line with past results, as approximately 77.8% of Trinidad segment production was from the higher royalty LOA and farmout agreement properties.

Canadian royalties were $395,000 or 17.9% of petroleum sales in 2015 versus 8.0% realized in 2014. Royalty expenses increased as a result of a one-time Saskatchewan resource charge incurred in the year.

Operating expenses

($000's)	**Year ended December 31, 2015**	2014[1]	% change
Trinidad			
Operating expenses	**13,322**	11,536	15
Canada			
Operating expenses	**3,292**	3,522	(7)
Company total	**16,614**	15,058	10

[1]Canadian 2014 results only include results for the six months ended December 31, 2014 as all properties were in the exploration stage prior to July 1, 2014. Trinidad comparative results are subsequent to the May 13, 2014 acquisition date.

Trinidad operating costs for the 2015 fiscal year were $22.81 per barrel, representing a decrease of 17% from $27.57 per barrel incurred in 2014. The Company focused on operating cost reductions throughout 2015, targeting fixed costs which represented approximately 55% of current year operating costs. On a US$ basis, 2015 Trinidad operating costs decreased 22% from US$23.09 per barrel incurred in 2014 to US$18.12 per barrel.

Canadian operating expenses for the year ended December 31, 2015 were $3,292,000 and were mainly driven from the Kerrobert property. Main cost drivers include electricity costs and gas costs for the facility incinerators. The facility was sold in February 2016 with an effective date of December 31, 2015.

Operating netbacks

($/bbl)	**Year ended December 31, 2015**	2014[2]	% change
Trinidad			
Reference price - Brent	**66.62**	109.04	(39)
Petroleum revenue	**58.45**	89.93	(35)
Royalties	**(18.35)**	(29.15)	(37)
Net revenue	**40.10**	60.78	(34)
Realized gain on derivatives	**10.59**	0.53	100
Operating expenses	**(22.81)**	(27.57)	(17)
Operating netback[1]	**27.88**	33.74	(17)
Canada			
Reference price - WTI	**61.95**	102.71	(40)
Petroleum revenue	**38.80**	69.64	(44)
Royalties	**(6.93)**	(5.60)	24
Net revenue	**31.87**	64.04	(50)
Operating expenses	**(57.75)**	(49.59)	16
Operating netback[1]	**(25.88)**	14.45	(100)
Company operating netback[1]	**23.09**	30.94	(25)

[1]See "*Non-GAAP Measures.*"
[2]Canadian 2014 results only include results for the six months ended December 31, 2014 as all properties were in the exploration stage prior to July 1, 2014. Trinidad comparative results are subsequent to the May 13, 2014 acquisition date.

Trinidad operating netbacks for the year ended December 31, 2015 were $16,272,000 or $27.88 per barrel versus $14,114,000 or $33.74 per barrel realized in 2014. Per barrel petroleum revenue decreased

35% based on the annual decrease in realized prices. Per barrel royalty expenses decreased on a commensurate basis with realized pricing. Realized 2015 hedging gains increased 2015 operating netbacks by $6,181,000 or $10.59 per barrel. 2014 hedging gains were $223,000 or $0.53 per barrel as the Company's ICE Brent based hedge contract commenced in December 2014. Per barrel operating expenses decreased 17% from 2014 based on the Company's measured approach to cost reductions.

Canadian operating losses for the year ended December 31, 2015 were $1,475,000 or $25.88 per barrel versus operating gains of $1,026,000 or $14.45 per barrel realized in 2014. With the 44% decrease in realized heavy oil pricing in 2015, the Company focused on economics versus production growth. The Company reduced capital costs by 90%, which coupled with asset dispositions reduced year-over-year production and revenue by 61% and 55%, respectively. Total operating costs were significantly cut as 2015 expenses of $3,292,000 were less than the $3,522,000 incurred in six months of 2014.

General and administrative ("G&A") expenses

($000's)	**Year ended December 31,**		%
	2015	2014[1]	change
Trinidad			
Gross G&A	**4,640**	3,062	
Capitalized G&A	**(532)**	(515)	
Net G&A	**4,108**	2,547	61
Canada			
Gross G&A	**7,157**	8,392	
Capitalized G&A	**(749)**	(984)	
Net G&A	**6,408**	7,408	(13)
Company total	**10,516**	9,955	6

[1]Trinidad comparative results are subsequent to the May 13, 2014 acquisition date.

G&A expenses primarily consist of management and administrative salaries and benefits, legal and professional fees, office rent, insurance, travel and other administrative expenses. In Trinidad, a total of 135 full-time-equivalents were working for Touchstone as at December 31, 2015 compared to 194 as at December 31, 2014. At Touchstone's Canadian head office, a total of 21 full-time-equivalents were employed as at December 31, 2015 versus 28 as at December 31, 2014.

For the year ended December 31, 2015, general and administrative costs were $10,516,000 compared to $9,955,000 in the comparative year. During the year ended December 31, 2015, the Company recognized non-recurring severance charges of $1,210,000 (2014 - $nil). After deducting these charges, general and administrative expenses were $9,306,000 or $14.52 per barrel. The Company continues to decrease G&A expenses, as fourth quarter expenses decreased 13% from the prior year comparative quarter.

Acquisition-related costs

The Company incurred $2,975,000 in legal, advisory, and severance charges related to the Old Touchstone acquisition during the year ended December 31, 2014.

Asset dispositions

The Company disposed of the following non-core Canadian assets in 2015:

- Effective March 1, 2015, the Company disposed of its producing Luseland cash-generating unit ("CGU") for net proceeds of $2,200,000. The CGU consisted of one producing well and various decommissioning obligations. Approximately 4,000 acres of undeveloped land and ancillary production equipment were also included in the sale. A gain of $130,000 was recognized in the statement of earnings as a result of the transaction.
- On July 14, 2015, the Company disposed of its non-core Dawson exploration CGU for net proceeds of $2,100,000 with no gain or loss recognized on the transaction.
- On July 30, 2015, the Company disposed of undeveloped land in its Beadle exploration asset CGU for net proceeds of $4,200,000. A gain of $3,351,000 was recognized in the statement of earnings as a result of the transaction.

On February 1, 2016, the Company closed a transaction to dispose of its Kerrobert property and equipment CGU and undeveloped land in its Luseland, Edam and Winter CGUs, all of which were included in the Company's Canadian operations segment. Through the disposition, the Company transferred its total Canadian segment discounted decommissioning liability balance of $4,028,000 to the purchaser.

The Company entered into an agreement on October 1, 2015 to dispose of its 70% working interest in the East Brighton offshore block for a 3.5%, non-convertible, no deductions gross overriding royalty on future production. At December 31, 2015, the CGU had a carrying value of $1,413,000 and associated decommissioning obligations of $1,413,000. As at December 31, 2015 the transaction had yet to close and the corresponding exploration asset and decommissioning obligation balances were classified as held for sale.

Loss/gain on marketable securities

The Company's investment in marketable securities consisted of common shares in the capital of Lightstream Resources Ltd. ("Lightstream"). The fair value of the investment in marketable securities was recorded on the consolidated statement of financial position at the end of each period, with the change in the fair value included in the determination of net earnings. During the three months ended March 31, 2015, the Company disposed of its remaining 243,613 Lightstream common shares. As a result, the loss on marketable securities for the year ended December 31, 2015 was $51,000 (2014 – gain of $1,922,000). Since the Old Touchstone acquisition, the Company sold all of its Lightstream common share holdings for net proceeds of $21,728,000 or $6.15 per share.

Net finance expenses

($000's)	**Year ended December 31,**		%
	2015	2014	change
Interest income	**(99)**	(161)	
Interest expense on bank loan	**412**	291	
Finance fees and other	**3,180**	339	
Net finance expenses	**3,493**	469	100
Less: amortized credit facility expense	**(2,168)**	(52)	
Cash finance expenses[1]	**1,325**	417	100

[1]See "*Non-GAAP Measures.*"

Interest income includes interest earned from funds on deposit and interest generated from a Trinidad capital equipment finance lease. Interest income has decreased from the prior year as the Company formerly had higher cash balances that were held in short-term interest bearing securities.

Fiscal year 2015 interest expenses were primarily bank loan interest and commitment fees. In 2014, interest expenses were mainly incurred on acquired Old Touchstone debt prior to its June 30, 2014 repayment.

Financing and other fees recognized in 2015 were comprised primarily of the amortization of fees associated with the Company's bank loan established in December 2014. This balance was amortized to net finance expenses during the year ended December 31, 2015 based on reductions of the bank loan borrowing base. Interest on Trinidad tax balances were included in other finance expenses. In 2014, finance fees mainly consisted of fees associated with the extinguishment of the acquired Old Touchstone long-term debt.

Foreign exchange and foreign currency translation

The Company's presentation currency is the Canadian dollar ("C$"). The Company and its Canadian subsidiaries have a Canadian dollar functional currency while the Trinidad subsidiaries have a Trinidad and Tobago dollar ("TT$") functional currency. Touchstone Exploration (Barbados) Ltd., a wholly-owned holding subsidiary of the Company, has a United States dollar ("US$") functional currency. In each reporting period, the change in values of the US$ and TT$ relative to the Canadian dollar reporting currency are recognized. The applicable rates used to translate the Company's TT$ and US$ denominated financial statement items were as follows:

	December 31, 2015	December 31, 2014	% change
Closing foreign exchange rates			
C$ / US$[1]	**0.7225**	0.8620	(16)
C$ / TT$	**4.6404**	5.4900	(15)

[1]Source: Bank of Canada nominal noon exchange rates.

The Company's main exposure to foreign currency risk relates to its working capital balances denominated in TT$ and debt balances denominated in US$. The TT$ and US$ have appreciated relative to the Canadian dollar throughout the year ended December 31, 2015. This resulted in the Company recognizing total foreign exchange gains of $1,814,000 during the year ended December 31, 2015 (2014 – gain of $1,034,000). Unrealized foreign exchange gains and losses may be reversed in the future as a result of fluctuations in exchange rates.

In addition, the assets and liabilities of the Company's subsidiaries are translated to Canadian dollars at the exchange rate on the reporting period 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. All resulting foreign currency differences are recorded in other comprehensive income in the Company's consolidated statement of earnings. As a result of the year to date appreciation of the TT$ vis a vis the Canadian dollar, foreign currency translation adjustment gains of $8,563,000 were recorded during the year ended December 31, 2015 (2014 – $4,455,000).

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. The options expire five years from the date of the grant. The maximum number of common shares issuable on the exercise of outstanding options at any time is limited to 10% of the issued and outstanding common shares. Share option amounts have been restated to reflect the impact of the two for one common share consolidation completed on May 13, 2014 as part of the Old Touchstone business combination.

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 two million incentive 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. The incentive share options expire five years from the date of the grant. Incentive share option amounts have also been restated to reflect the impact of the two for one common share consolidation completed on May 13, 2014 as part of the Old Touchstone business combination.

During the year ended December 31, 2015, share-based compensation expense of $363,000 was recorded compared to $385,000 recognized in 2014. Share-based compensation expense decreased from the prior year as unvested share options were forfeited based on employee departures, which resulted in a recovery of the related unvested share-based compensation expense initially recorded.

During the 2015 fiscal year, the Board of Directors approved and granted 1,891,800 share options and nil incentive share options, respectively (2014 – 4,685,090 and 250,000). At December 31, 2015, share options and incentive share options outstanding represented 6.7% of the common shares outstanding (2014 – 6.2%).

Depletion and depreciation expense

($000's)	**Year ended December 31,**		%
	2015	2014[1]	change
Trinidad			
Depletion and depreciation expense	**7,762**	3,516	100
Canada			
Depletion and depreciation expense	**618**	1,686	(63)
Company total	**8,380**	5,202	61

[1]Trinidad comparative results are subsequent to the May 13, 2014 acquisition date.

Depreciation expense is recorded relating to corporate assets in Canada and motor vehicles and rig equipment in Trinidad. Equipment and corporate assets are depreciated on a declining balance basis. The Company's producing assets in Trinidad are subject to depletion expense. Effective July 1, 2014, the Company transferred the carrying values of the Kerrobert and Luseland properties to property and equipment and began to recognize associated depletion expenses. The net carrying value of producing assets is depleted using the unit of production method by reference to the ratio of production in the year over the related proven and probable reserves while also taking into account the estimated future development costs necessary to bring those reserves into production. As at December 31, 2015, $70,764,000 and $1,019,000 in future development costs have been added to the respective Trinidad and Canada cost bases for depletion calculation purposes (December 31, 2014 - $67,857,000 and $3,060,000). During the year ended December 31, 2015, $1,281,000 and $118,000 in general and administrative expenses and share-based compensation was capitalized, respectively (2014 – $1,228,000 and $129,000, respectively).

Trinidad depletion and depreciation expense was $7,762,000 or $13.29 per barrel during the year ended December 31, 2015. Trinidad depletion expense increased from the prior year due to a full year of results and related production in 2015. Canadian depletion and depreciation costs decreased from 2014 as a result of the Luseland producing asset sale effective March 1, 2015 and decreased Kerrobert CGU production in 2015.

Impairment

The Company assesses exploration asset and property and equipment indicators of impairment on a quarterly basis. Impairment consisted of the following non-cash charges:

($000's)	**Year ended December 31,**		%
	2015	2014	change
Trinidad CGU			
Exploration assets – Cory Moruga	**948**	-	
Exploration assets – East Brighton	**(317)**	426	
Property and equipment – Coora	**12,549**	16,665	
Property and equipment – WD-4	**8,840**	-	
Property and equipment – WD-8	**9,768**	10,050	
Property and equipment – New Dome	**303**	-	
Property and equipment – South Palo Seco	**60**	-	
Property and equipment – Barrackpore	**1,766**	1,500	
Property and equipment – Fyzabad	**1,491**	6,128	
Property and equipment – San Francique	**1,720**	2,400	
	37,128	37,169	-
Canada CGU			
Exploration assets – Dawson	**2,562**	31,286	
Exploration assets – Kerrobert	**-**	898	
Exploration assets – Luseland	**122**	4,512	
Exploration assets – Various	**553**	-	
Property and equipment – Kerrobert	**(2,223)**	-	
Property and equipment – Luseland	**-**	(1,663)	
Other	**-**	458	
	1,014	35,491	(97)
Company total	**38,142**	72,660	(48)

During the year ended December 31, 2015, the following exploration asset impairment charges were recognized:

- Impairment charges of $948,000 were recorded with respect to the Company's interest in the Trinidad Cory Moruga block based on uneconomic well performance. The fair value of the CGU was assessed at $nil.
- An impairment reversal of $317,000 was recorded related to the East Brighton block CGU during the year ended December 31, 2015. The exploration asset was written up to its $1,413,000 decommissioning obligation value based on a sales agreement executed on October 1, 2015. The fair value of the CGU was determined to be $nil, as the value of the 3.5% gross overriding royalty was not reliably determinable.
- An impairment charge of $2,562,000 was recorded during the year ended December 31, 2015 to write down the Dawson CGU to the lesser of carrying value and the estimated recoverable amount based on $2,100,000 transaction proceeds received in July 2015.
- Impairment charges of $675,000 were recorded relating to the Company's Canadian undeveloped land in Luseland and other, which was written down to $491,000 representing the estimated fair value less costs to sell as at December 31, 2015.

Property and equipment impairment charges of $36,497,000 were recorded during the year ended December 31, 2015 on crude oil assets located in the Trinidad operating segment. The impairment charges, attributed to all Trinidad CGUs, were the result of sustained declines in forecasted short and long-term crude oil pricing. The recoverable amount of the impaired CGUs was determined to be $59,280,000 as at December 31, 2015. At June 30, 2015, the Company's Trinidad decommissioning obligations were revalued using the adjusted long-term Trinidad inflation rate of 4%, which represented a 1% increase from the previous estimate. The corresponding $2,503,000 increase to the decommissioning obligation asset balance was valued at $nil and charged to impairment, as the restated CGUs were initially impaired on December 31, 2014 and no headroom remained.

The Company recognized an impairment reversal of $2,223,000 relating to the Kerrobert CGU based on transaction proceeds received subsequent to December 31, 2015. The transaction closed on February 1, 2016 based on a sales agreement executed in January 2016. Accordingly, the property and equipment and corresponding decommissioning obligation balances were not classified as held for sale as at December 31, 2015.

Further information regarding the impairment charges for the years ended December 31, 2015 and 2014 is included in Note 9 in the Company's consolidated financial statements.

Accretion and decommissioning obligations

During the year ended December 31, 2015, the Company recorded $624,000 (2014 - $452,000) in accretion related to its decommissioning obligations. The increase was mainly a result of the decommissioning obligations acquired in the Old Touchstone acquisition.

The Company's decommissioning obligations relate to future site restoration and abandonment costs including the costs of production equipment removal based on current regulations and economic circumstances. The total decommissioning obligation is estimated by management based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities, and the estimated timing of the costs to be incurred in future periods. The accounts payable balance of the decommissioning obligation represents accrued amounts relating to a Trinidad abandonment fund that are short-term in nature. Decommissioning obligation details as at December 31, 2015 were as follows:

	# of well/facility locations	**Undiscounted balance** *($000's)*	**Inflation adjusted balance** *($000's)*	**Discounted balance** *($000's)*
Trinidad	804	26,809	65,749	12,959
Canada	47	3,708	4,925	4,028
Company total	**851**	**30,517**	**70,674**	**16,987**

As at December 31, 2015, the Company estimated the total undiscounted cash flows required to settle its decommissioning obligations was approximately $26,809,000 for Trinidad and $3,708,000 for Canada (December 31, 2014 - $29,757,000 and $5,357,000). The majority of these obligations are anticipated to be incurred in 2026 and are expected to be funded from the Trinidad abandonment fund and the Company's internal resources available at the time of settlement. Decommissioning liabilities have been discounted using a weighted average risk-free rate of 7.5% and 1.4% for Trinidad and Canada based liabilities, respectively (December 31, 2014 – 7.5% and 1.8%). The liabilities have been calculated using an inflation rate of 4% and 2% per annum for Trinidad and Canada based liabilities, respectively (December 31, 2014 – 3% and 2%).

At June 30, 2015, the Company's Trinidad decommissioning obligations were revalued using the adjusted long-term Trinidad inflation rate of 4%, which represented a 1% increase from the previous estimate. The corresponding $2,503,000 increase to the decommissioning obligation asset balance was included as a change in estimate. At December 31, 2015, the Company revised its estimated costs to settle Trinidad well decommissioning obligations to US$35,000 per well (2014 – US$50,000 per well), which resulted in a decrease to the estimated liability of $8,170,000. This decrease was slightly offset by the increase in Petrotrin decommissioning obligations that was driven by 2015 production, which increases the Company's proportionate interest in future well abandonments. The changes in Canadian segment decommissioning obligation estimates were a result of the decrease in the estimated Canadian weighted average risk-free rate from 2014.

As previously disclosed herein, on February 1, 2016, the Company closed a transaction to dispose of its Kerrobert property and equipment CGU and various undeveloped land. Through the disposition, the Company transferred its total Canadian segment discounted decommissioning liability balance of $4,028,000 to the purchaser.

Decommissioning liabilities are considered critical accounting estimates. There are significant uncertainties related to decommissioning expenditures, and the impact on the financial statements could be material. The eventual timing of and costs for these expenditures could differ from current estimates.

Income tax expense and income taxes payable

The Company is subject to the following petroleum taxes and levies to the Government of Trinidad and Tobago:

- Supplemental Petroleum Tax ("SPT") 18% of gross revenue less royalties
- Petroleum Profits Tax ("PPT") 50% of net chargeable profits
- Unemployment Levy ("UL") 5% of net chargeable profits
- Green Fund Levy 0.1% of gross revenue

Effective January 1, 2016, the Green Fund Levy increased to 0.3% of gross revenue. The Company also has a Trinidad based service company that is subject to the greater of a 25% corporate tax calculated on net income or a 0.2% business levy calculated on gross sales. The service company is also subject to the green fund levy noted above. Trinidad also charges withholding taxes of 10% of interest paid to Canadian sources.

SPT is calculated and remitted on a quarterly basis. Actual rates vary based on the realized selling prices of oil in the applicable quarter. The SPT tax is 0% when the weighted average realized price of oil for a given quarter is below US$50.00 per barrel. The revenue base for the calculation of SPT is gross revenue less royalties, less 20% investment tax credits for certain allowable capital expenditures incurred in the applicable fiscal quarter. Annual PPT, UL taxes and corporate taxes are calculated based on net chargeable profits. Net chargeable profits are determined by calculating gross revenue less royalties, SPT paid during the year, capital allowances, operating, administration and certain finance expenses. Withholding taxes are payable when Trinidad entities pay interest on head office intercompany loans. Interest charges are deductible for PPT and UL purposes when paid.

($000's)	**Year ended December 31,**		%
	2015	2014[1]	change
Trinidad			
SPT	**551**	1,693	
PPT	**255**	235	
UL	**25**	23	
Business levy	**8**	24	
Green fund levy	**52**	59	
Withholding taxes	**-**	30	
	891	2,064	(57)
Canada			
Current income tax recovery	**(447)**	-	-
Company total	**444**	2,064	(78)

[1]Trinidad comparative results are subsequent to the May 13, 2014 acquisition date.

Trinidad income taxes for the year ended December 31, 2015 were $1.53 per barrel. The decrease in current tax expense from the prior period was a result of decreased Trinidad cash flows, which was driven by decreases in realized oil prices and production. Furthermore, only one of the Company's operating subsidiaries paid two fiscal quarters of SPT during 2015, as realized prices received were below US$50.00 for the second half of the year. During the year ended December 31, 2015, the Company filed its 2014 Trinidad tax returns resulting in an additional $280,000 owing in PPT and UL taxes.

The Company's Canadian operations continue to remain in a loss position and are not taxable. The Company received 2013 and 2014 Canadian tax refunds totaling $447,000 during the year ended December 31, 2015.

Old Touchstone previously acquired a Trinidad subsidiary that had overdue 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 subsidiary specified that upon confirmation from the BIR, the 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 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 December 31, 2015, $3,314,000 in related interest was accrued in income taxes payable.

The 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. The Company continues to work with the seller and 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.

The December 31, 2015 income tax payable balance was comprised of the following:

($000's)	**Principal**	**Interest**	**Total**
Prior year taxes (2014 and prior)	(72)	4,709	4,637
Current year tax accruals less instalments (2015)	-	-	-
Income taxes payable	**(72)**	**4,709**	**4,637**

The deferred income tax liability balance represents the estimated future tax consequences attributable to differences between financial statement carrying amounts of assets and liabilities and their respective tax bases. The Company currently does not recognize any benefit for its Canadian tax losses. The deferred tax liability balance mainly relates to the discrepancy of the fair values over the carrying values of the assets acquired in the Old Touchstone business combination. During the year ended December 31, 2015, the Company recorded deferred tax recoveries of $17,143,000 (2014 - $15,681,000). The 2015 deferred tax recoveries were mainly a result of the 2015 Trinidad property and equipment impairment charges.

At December 31, 2015, the Company had approximately $24,997,000 (2014 - $13,409,000) in Trinidadian non-capital losses which could be carried forward indefinitely to reduce petroleum profit tax and corporate tax in future years. The benefit of $10,251,000 of Trinidad non-capital losses were not recognized as at December 31, 2015. The Company had approximately $51,416,000 (2014 – $43,251,000) in Canadian non-capital losses which begin to expire in 2026. The benefit of Canadian tax loss carry forwards were not recognized as at December 31, 2015 and 2014.

Funds flow netbacks

($/bbl)	**Year ended December 31,** **2015**	2014[2]	% change
Trinidad			
Operating netback[1]	**27.88**	33.74	(17)
G&A	**(7.04)**	(6.09)	16
Cash finance expense[1]	**(3.96)**	-	(100)
Current income taxes	**(1.53)**	(4.93)	(69)
Funds flow netback[1]	**15.35**	22.72	(32)
Canada			
Operating netback[1]	**(25.88)**	14.45	(100)
G&A	**(112.41)**	(50.23)	100
Cash finance expense[1]	**17.33**	(2.83)	(100)
Current income taxes	**7.84**	-	100
Funds flow netback[1]	**(113.12)**	(38.61)	100
Company funds flow netback[1]	**3.92**	8.96	(56)

[1]See "*Non-GAAP Measures.*"
[2]Canadian 2014 results only include operating netback results for the six months ended December 31, 2014 as all properties were in the exploration stage prior to July 1, 2014. Trinidad comparative results are subsequent to the May 13, 2014 acquisition date.

For the year ended December 31, 2015, Trinidad funds flow netbacks were $7,157,000 or $15.35 per barrel versus $8,901,000 or $22.72 per barrel realized during the comparative 2014 year. Funds flow per barrel in 2015 decreased from the prior year as a result of significantly lower commodity prices, partially offset by realized hedging gains and lower taxes. Canadian operations incurred a $4,249,000 funds flow netback loss, which decreased from the $8,511,000 loss incurred in 2014. Per barrel netback losses increased from the prior year based on the decreased Canadian production base and operating losses incurred in 2015.

Capital Expenditures

Exploration asset cash expenditures

($000's)	**Year ended December 31,** **2015**	2014[1]	% change
Trinidad			
Lease payments	**310**	-	
Geological	**268**	417	
Drilling and completions	**-**	764	
Other	**360**	117	
	938	1,298	(28)
Canada			
Land acquisitions	**20**	495	
Drilling and completions	**-**	763	
Production equipment and facilities	**(16)**	3,810	
Capitalized G&A	**-**	271	
Capitalized losses	**241**	4,656	
Other	**62**	62	
	307	10,057	(97)
Company total	**1,245**	11,355	(89)

[1]Trinidad comparative results are subsequent to the May 13, 2014 acquisition date.

During the year ended December 31, 2015, the Company incurred annual lease payments, geological study costs and initial seismic costs relating to the Trinidad Ortoire exploration block in Trinidad. The Company also incurred various finance fees to support letters of credits for its East Brighton and Ortoire blocks. Prior year costs were predominately incurred in the Cory Moruga block, as the Company participated in the drilling of one gross well (0.16 net). Based on poor 2015 testing results, these costs were impaired during the year ended December 31, 2015.

Canadian exploration additions in 2015 primarily related to Dawson capitalized losses. In 2014, costs were incurred for the Dawson cyclical steam project and the first two fiscal quarters of capitalized losses and gains at Kerrobert and Luseland, respectively. On July 1, 2014 the Kerrobert and Luseland properties were evaluated as being commercially viable and transferred to property and equipment. Consequently, any additions related to Kerrobert and Luseland subsequent to July 1, 2014 were captured in property and equipment additions. The Dawson cyclical steam project was terminated in October 2014, and the Company disposed of the Dawson property in July 2015.

Property and equipment cash expenditures

($000's)	**Year ended December 31,**		%
	2015	2014[1]	change
Trinidad			
Drilling and completions	**1,778**	17,462	
Production equipment and facilities	**478**	1,352	
Capitalized G&A	**1,255**	1,144	
Rig equipment and other	**-**	3,017	
	3,511	22,975	(85)
Canada			
Production equipment and facilities	**-**	395	
Capitalized G&A	**26**	84	
Other	**35**	156	
	61	635	(90)
Company total	**3,572**	23,610	(85)

[1]Trinidad comparative results are subsequent to the May 13, 2014 acquisition date.

Trinidad operations incurred $1,778,000 of drilling and completions capital expenditures during the year ended December 31, 2015, as twenty-eight completions and recompletions were performed in the year. The Company reduced its capital expenditures in 2015 based on the fall in commodity prices. Minimal capital was spent on Canadian operations throughout 2015 as the Company focused on limiting its Kerrobert property operating losses.

Capital efficiency

The efficiency of the Company's Trinidad capital program for the year ended December 31, 2015 is summarized below:

	Proved	**Proved Plus Probable**
Capital expenditures *($000's)*		
Exploration capital expenditures	938	938
Development capital expenditures	3,511	3,511
	4,449	4,449
Change in future development costs[1] *($000's)*	2,290	2,852
Total capital	**6,739**	**7,301**
Total reserve additions[2] *(Mbbls)*	**426**	**1,252**
Finding and development costs[2] *($/bbl)*	**15.81**	**5.83**

[1]Calculation includes changes in future development costs.
[2]See "*Advisory on Reserves Information.*"

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, fluctuations in C$/US$ and C$/TT$ exchange rates and fluctuations in LIBOR interest 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, 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, particularly in relation to prices received for its oil production. 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. The Company has the following commodity financial contracts in place as at the date of this MD&A:

Contract	Volume	Pricing
ICE Brent crude oil swap		
January 1, 2016 – April 30, 2016	800 barrels per day	US$66.50 per barrel
May 1, 2016 – May 31, 2016	800 barrels per day	US$68.00 per barrel
June 1, 2016 – October 31, 2016	800 barrels per day	US$65.00 per barrel
November 1, 2016 – December 31, 2016	800 barrels per day	US$50.00 per barrel
January 1, 2017 – January 31, 2017	800 barrels per day	US$40.50 per barrel
ICE Brent crude oil purchased call		
January 1, 2016 –May 31, 2016	800 barrels per day	US$90.00 per barrel
November 1, 2016 – December 31, 2016	800 barrels per day	US$50.00 per barrel
ICE Brent crude oil sold put		
November 1, 2016 – December 31, 2016	800 barrels per day	US$31.00 per barrel

As at December 31, 2015, the Company recorded a financial derivative asset of $7,650,000 related to commodity management contracts (December 31, 2014 - $3,133,000). During the year ended December 31, 2015, the Company realized a gain of $6,181,000 related to commodity management contracts (2014 - $223,000). As a result of the increase in the fair value of the Company's commodity contracts, unrealized gains on financial derivatives of $2,654,000 were recognized during the year ended December 31, 2015 (2014 - $3,123,000).

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 Trinidad and Tobago dollar can have a significant effect on reported results. The Company's foreign exchange gain or losses primarily include unrealized foreign exchange gains on losses on the translation of the Company's US$ denominated bank loan and the translation of the Company's TT$ denominated working capital balances.

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 year ended December 31, 2015. For the year ended December 31, 2015, with all other variables held constant, a 1% change in the Canadian dollar to TT$ exchange rate would have resulted in an approximate $153,000 (2014 - $588,000) increase or decrease in net earnings.

Interest rate risk

Interest rate risk arises from changes in market interest rates that may affect earnings, cash flows and valuations. The Company is exposed to interest rate risk in relation to interest expense on its variable rate bank loan.

The Company had no contracts in place to manage interest rate risk as at or during the year ended December 31, 2015. For the year ended December 31, 2015, with all other variables held constant, a 1% change in the bank loan interest rate would have resulted in an approximate $84,000 (2014 - $4,000) increase or decrease in net earnings.

Liquidity and Capital Resources

($000's)	**December 31, 2015**	December 31, 2014
Net (surplus) debt[1]	**(987)**	6,926
Shareholders' equity	**52,657**	65,758

[1]See "*Non-GAAP Measures.*"

The Company exited 2015 with a net surplus position of $987,000, including $4,710,000 in cash. The Company's bank loan balance was $8,304,000 (US$6,000,000), which increased by US$1,000,000 from December 31, 2014. Net debt decreased based on $8,531,000 in proceeds from dispositions that closed during the year. The Company funded its combined $4,817,000 of capital expenditures partly from $2,908,000 in operating funds flows with the remainder from the aforementioned proceeds from dispositions.

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, 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, production expectations and other factors that in the Company's view would impact cash flow.

Bank loan

On December 4, 2014, the Company entered into a secured term facility with a major Canadian bank maturing on December 4, 2017. Total borrowings permitted under the facility cannot exceed the borrowing base, which was US$12,000,000 at December 31, 2015 (2014 – US$15,000,000). The borrowing base is redetermined by the lender semi-annually on April 1 and October 1 and is determined based on, among other things, the Company's Trinidad proved oil and gas reserves and the lender's view of the current and forecasted commodity prices. The facility is principally secured by a pledge of the Company's equity interest in its material subsidiaries, together with their respective assets.

At December 31, 2015, $8,304,000 (US$6,000,000) was drawn against the bank loan (2014 - $5,800,000 or US$5,000,000). In December 2014 the Company issued a US$6,000,000 letter of credit relating to work commitments on the East Brighton block which restricts the amount available on the credit facility.

This letter of credit is expected to be cancelled upon closing of the East Brighton disposition. As at December 31, 2015, $nil was available to be drawn on the credit facility (2014 – US$4,000,000).

Advances on the facility bear interest at the LIBOR rate plus an applicable margin. The margin ranges from 4.05% to 4.80% per annum, depending on utilization. Undrawn amounts under the facility bear a commitment fee of 0.85%, and outstanding amounts bear an additional interest rate of 2% during any default periods. For the year ended December 31, 2015, the effective interest rate, including the commitment fee and default interest, was 5.6% (month ended December 31, 2014 – 5.9%).

Repayments of principal are not required provided that the borrowings under the loan do not exceed the authorized borrowing amount and that the Company is in compliance with all covenants, representations and warranties. The Company is subject to the following bank loan covenants:

- Total debt to EBITDAX ratio: the Company will not permit the ratio of total debt to EBITDAX for the trailing four fiscal quarters to be greater than 3.00 to 1.00. "EBITDAX" means, for any period, the sum of consolidated net income for such period plus the following expenses or charges to the extent deducted from consolidated net income in such period: interest, income taxes, depreciation, depletion, amortization, exploration expenses and all non-cash charges, minus all non-cash income added to consolidated net income.
- Interest coverage ratio: the Company will not, as of the last day of any fiscal quarter, permit its ratio of EBITDAX for the period of four fiscal quarters then ending to interest expense for such period to be less than 2.50 to 1.00.
- Monthly production: the Company shall not permit the amount equal to the net production volume of oil and gas from its Trinidad properties for each calendar month divided by the total number of days in such calendar month to be less than 1,600 barrels per day.

The Company’s monthly average Trinidad oil production and minimum oil production requirements under its credit facility agreement were as follows:

Period	**Trinidad production *(bbls/d)***	**Minimum production requirements *(bbls/d)***
May 2015	1,497	1,600
June 2015	1,616	1,600
July 2015	1,550	1,600
August 2015	1,571	1,600
September 2015	1,533	1,600
October 2015	1,472	1,500
November 2015	1,484	1,500
December 2015	1,510	1,500
January 2016	1,377	1,600
February 2016	1,369	1,350

The Company executed a waiver with its lender on September 23, 2015 relating to the May, July and August production covenant breaches. The Company obtained a waiver from its lender on November 3, 2015 to cure the September production covenant breach. Finally, the Company and its lender executed a waiver to cure the October and November monthly covenant breaches on December 31, 2015. As at December 31, 2015 the Company was in compliance with all covenants, obligations and conditions of the facility.

The Company was in breach of its January 2016 bank loan monthly production volume covenant. Effective March 8, 2016, the Company and its lender executed an Amendment and Limited Waiver to the Credit Agreement (“Waiver”) to waive the covenant breach. The Waiver also made certain amendments to the bank loan, including a reduction of the Trinidad minimum production covenant (previously set at 1,600 barrels of oil per day) to 1,350 barrels of oil per day for the months of February and March 2016 and 1,400 barrels of oil per day thereafter.

The Waiver also amends the bank loan to require mandatory prepayments of US$2,000,000 on March 8, 2016 and US$1,000,000 on April 8, 2016. These prepayments are also considered a reduction of the bank loan borrowing base. Furthermore, the borrowing base will be reduced by US$6,000,000 when the Company's letter of credit is cancelled following the expected sale of the East Brighton property. The Waiver also requires that the Company prepay an amount equal to the refund of all or any portion of the US$2,080,000 deposit paid under the terminated Trinidad asset acquisition. As at December 31, 2015, the $8,304,000 (US$6,000,000) bank loan balance was classified as a current liability.

The interim reductions to the credit facility borrowing base are subject to a borrowing base redetermination scheduled on April 1, 2016. This borrowing base redetermination will incorporate the Company's December 31, 2015 independent reserves evaluation. Based on this evaluation, the Company believes the future net revenues of its reserves will allow for adequate borrowing base capacity to fund its 2016 capital commitments.

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 the 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 assess new sources of financing available and to manage its expenditures to reflect current financial resources in the interest of sustaining long-term viability.

The Company is awaiting the redetermination of its bank loan and is also seeking alternative sources of financing. There can be no certainty as to the ability of the Company to successfully restructure its credit facility, or obtain new financing should low crude oil prices persist. There is also no certainty that the revised borrowing base of US$9,000,000 will be re-affirmed during the April 1, 2016 semi-annual borrowing base redetermination.

Undiscounted cash outflows relating to financial liabilities as at December 31, 2015 was as follows:

($000's)	**Less than 1 year**	**1 – 3 years**	**4 – 5 years**	**Total**
Accounts payable and accrued liabilities	12,219	-	-	12,219
Income taxes payable	4,637	-	-	4,637
Bank loan	8,304	-	-	8,304
Total financial liabilities	**25,160**	**-**	**-**	**25,160**

Uncertain tax position

The Company has an uncertain tax position as disclosed in the *"Income taxes"* section above that could impact future liquidity. At this time, management does not believe that the Company will be required to make any future principal payments or interest payments that are otherwise accrued relating to the issue.

Fourth Quarter Results

	Three months ended December 31, 2015	2014[1]
Operating		
Average daily oil production (bbls/day)		
Trinidad	**1,498**	1,896
Canada	**73**	387[2]
Company total	**1,571**	2,283[2]
Average realized oil prices before derivatives ($/bbl)		
Trinidad	**50.64**	78.30
Canada	**27.15**	61.00[2]
Company total	**49.54**	75.36[2]
Trinidad operating netback[3] ($/bbl)		
Reference price – Brent	**58.02**	86.64
Petroleum revenue	**50.64**	78.30
Royalties	**(15.95)**	(25.40)
Net revenue	**34.69**	52.90
Realized gain on derivatives	**17.04**	1.28
Operating costs	**(23.77)**	(25.12)
Operating netback	**27.96**	29.06
Canada operating netback[3] ($/bbl)		
Reference price – WTI	**55.86**	82.98
Petroleum revenue	**27.15**	61.29
Royalties	**(8.46)**	(6.92)
Net revenue	**18.69**	54.37
Operating costs	**(88.86)**	(46.37)
Operating netback	**(70.17)**	8.00
Financial *($000's except share and per share amounts)*		
Funds flow from operations[3]		
Trinidad	**1,201**	3,598
Canada	**207**	(1,351)
Company total	**1,408**	2,247
Per share – basic and diluted[3,4]	**0.02**	0.03
Net earnings (loss)	**152**	(49,356)[5]
Per share – basic and diluted[4]	**0.01**	(0.59)
Capital expenditures		
Exploration assets	**612**	504
Property and equipment	**578**	9,960
Company total	**1,190**	10,464
Weighted average shares outstanding[4]		
Basic	**83,087,143**	83,059,643
Diluted	**83,294,151**	83,059,643

[1]Canadian 2014 results only include results for the six months ended December 31, 2014 as all properties were in the exploration stage prior to July 1, 2014. Trinidad comparative results are subsequent to the May 13, 2014 acquisition date.
[2]Average daily production and average realized prices include Canadian exploration property results.
[3]See "*Non-GAAP Measures.*"
[4] All current and comparative share amounts have been adjusted to reflect the two for one common share consolidation completed on May 13, 2014.
[5]Adjusted based on final Old Touchstone purchase price allocation.

Production volumes averaged 1,571 bbls/d during the fourth quarter of 2015, which represented a decline of 31% from the fourth quarter of 2014. Trinidad sales volumes decreased 21% from the prior year comparative quarter based on minimal capital spending incurred in 2015. Canada production declined by 81% from the fourth quarter of 2014 due to 2015 asset dispositions and minimal Kerrobert property operating and capital costs incurred throughout 2015.

Trinidad operating netbacks generated $3,852,000 ($27.96 per barrel) during the fourth quarter versus $5,067,000 ($29.06 per barrel) recognized in the comparative 2014 period. The 21% production decrease combined with a 35% decrease in realized pricing were slightly offset by an increase of $2,125,000 in realized derivative gains and a 25% reduction in 2015 operating costs. Canadian operations incurred operating losses of $473,000 during the three months ended December 31, 2015 versus generating positive operating netbacks of $275,000 during the final quarter of 2014.

For the three months ended December 31, 2015, funds flow from operations was $1,408,000 ($4.97 per barrel) versus $2,247,000 ($10.66 per barrel) realized in the comparative 2014 period. Trinidad funds flow from operations of $1,201,000 and Canadian funds flow from operations of $207,000 were recognized in the fourth quarter of 2015 (2014 - $3,598,000 and losses of $1,351,000, respectively).

The Company incurred net earnings of $152,000 ($0.01 per basic share) during the three months ended December 31, 2015 versus a net loss of $49,356,000 ($0.59 per basic share) recognized in the comparative 2014 period. Prior year net losses were mainly a result of $67,714,000 in asset impairment charges, offset by a corresponding deferred tax recovery of $15,877,000. The majority of the Company's 2015 asset impairments were recorded during the three months ended September 30, 2015.

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 and lease operating agreements. 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 the Ortoire license and production agreement with the MEEI and various lease commitments for office space and light-duty vehicles. The Company's estimated capital requirements over the next five years and thereafter are as follows:

($000's)	**2016**	**2017**	**2018**	**2019**	**2020**	**Thereafter**
Minimum work obligations and lease payments						
Coora block	2,799	2,801	173	106	177	-
WD-4 block	2,046	1,979	2,050	115	118	-
WD-8 block	1,450	1,454	1,527	78	152	-
New Dome block	53	5	5	5	5	5
South Palo Seco block	1,778	51	54	57	60	64
Ortoire exploration commitments	2,862	6,538	4,477	2,416	355	-
Office leases	827	615	193	149	-	-
Equipment leases	50	-	-	-	-	-
Total minimum payments	**11,865**	**13,443**	**8,479**	**2,926**	**867**	**69**

Under the terms of its Trinidad concessions, the Company must fulfill the minimum work obligations over the specific license term and thus has restricted discretion over the timing of when capital commitments are satisfied within a license period. In total, the Company is obligated to drill one well in 2016 and drill ten wells and perform thirteen heavy workovers prior to the end of 2020. The Company has a various letters of credit totaling US$299,000 related to its work commitments on its Petrotrin concessions.

The Company has provided a US$3,313,000 letter of credit in favour of the MEEI related to Ortoire block exploration commitments. Export Development Canada has provided a performance security guarantee to support this letter of credit. It is the Company's intention to find a strategic partner to farmout a portion of these exploration commitments. The Company's current estimated costs and timing of its future Ortoire exploration commitments, which includes acquiring and processing 85 line kilometers of 2D seismic and the drilling of four vertical wells, are as follows:

($000's)	**2016**	**2017**	**2018**	**2019**	**2020**	**Thereafter**
Lease payments	296	310	325	340	355	-
Geological studies	353	-	-	-	-	-
2D seismic	2,213	4,152	-	-	-	-
Drilling commitments	-	2,076	4,152	2,076	-	-
Total minimum payments	**2,862**	**6,538**	**4,477**	**2,416**	**355**	**-**

The Company has a US$6,000,000 letter of credit relating to work commitments on the East Brighton block which restricts the amount available on the credit facility. This letter of credit is expected to be cancelled upon closing of the East Brighton disposition. The Company has excluded an estimated US$4,200,000 in future East Brighton work obligations in its commitments disclosure above.

Related Party Transactions

The Company is a party to transactions with Lightstream and Alvopetro Energy Ltd. ("Alvopetro"), which are related parties to the Company due to common Directors. The transactions include management fees charged by Lightstream, natural gas purchased for the Company's Canadian operating segment from Lightstream and an office sub-lease with Alvopetro. Furthermore, the Company's Corporate Secretary is a partner of the Company's legal counsel, Norton Rose Fulbright Canada LLP ("Norton Rose").

($000's)	**Year ended December 31,**	
	2015	2014
Management fees charged by Lightstream	**-**	60
Gas purchased from Lightstream	**146**	700
Office rent charged to Alvopetro	**259**	248
Legal fees charged by Norton Rose	**194**	130

Management fees were charged based on a cost recovery basis while all other transactions were recorded at fair value. As at December 31, 2015, $38,000 and $nil in related party amounts were included in accounts payable and accounts receivable, respectively (2014 - $286,000 and $2,000).

The Company has determined that the key management personnel of the Company are comprised of its directors and three executive officers. Key management personnel compensation paid or payable was as follows:

($000's)	**Year ended December 31,**	
	2015	2014
Salaries, director fees and short-term benefits included in general and administrative expenses	**1,012**	1,725
Termination benefits included in general and administrative expenses	**523**	-
Termination benefits included in transaction costs	**-**	456
Share-based compensation	**297**	372
Key management compensation	**1,832**	2,553

Financial Instruments

The Company's non-derivative financial instruments recognized on the consolidated statements of financial position consist of cash, accounts receivable, accounts payable and accrued liabilities and bank loan. Non-derivative financial instruments are recognized initially at fair value. The fair values of the current financial instruments approximate their carrying value due to their short-term maturity. The carrying value of the bank loan approximates fair value due to the floating interest rate on the facility.

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, incentive share options and share purchase warrants as at December 31, 2015 and 2014.

	December 31, 2015	December 31, 2014
Common shares outstanding – end of period	**83,087,143**	83,059,643
Share options outstanding – end of period	**5,308,445**	4,814,085
Incentive share options outstanding – end of period	**298,125**	336,750
Warrants outstanding – end of period	**2,260,800**	2,260,800

Common share, share options and warrant balances have been restated to reflect the impact of the two for one common share consolidation completed on May 13, 2014 as part of the Old Touchstone business combination.

As at the date of this MD&A, there were 83.1 million common shares outstanding, 5.3 million share options and incentive share options outstanding and 2.3 million share purchase warrants outstanding.

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	December 31, 2015	September 30, 2015	June 30, 2015	March 31, 2015
Operating				
Average daily production *(bbls/d)*	1,571	1,638	1,786	2,036
Average oil prices before derivatives *($/bbl)*	49.54	56.24	65.12	55.25
Operating netback[1] *($/bbl)*				
Petroleum revenue	49.54	56.24	65.12	55.25
Royalties	(15.60)	(18.06)	(19.24)	(16.41)
Net revenue	33.94	38.18	45.88	38.84
Realized gain on derivatives	16.25	12.12	3.86	7.53
Operating costs	(26.81)	(26.75)	(27.17)	(23.43)
Operating netback	23.38	23.55	22.57	22.94
Operating netback[1] *($000's)*				
Petroleum revenue	7,159	8,476	10,583	10,122
Royalties	(2,254)	(2,722)	(3,127)	(3,007)
Net revenue	4,905	5,754	7,456	7,115
Realized gain on derivatives	2,348	1,826	628	1,379
Operating costs	(3,874)	(4,032)	(4,415)	(4,293)
Operating netback	3,379	3,548	3,669	4,201
Financial *($000's except share and per share amounts)*				
Funds flow from operations[1]	1,408	313	762	425
Per share – basic and diluted[1,2]	0.02	0.01	0.01	0.01
Net loss	152	(12,666)	(8,505)	(1,128)
Per share – basic and diluted[2]	0.01	(0.15)	(0.10)	(0.01)
Capital expenditures				
Exploration assets	612	154	291	188
Property and equipment	578	679	1,144	1,171
Company total	1,190	833	1,435	1,359
Total assets - end of period	100,619	101,564	125,788	141,486[3]
Net (surplus) debt[1] - end of period	(987)	39	5,755	6,172[3]
Weighted average shares outstanding[2]				
Basic	83,087,143	83,080,866	83,079,643	83,073,865
Diluted	83,294,151	83,080,866	83,079,643	83,073,865
Outstanding shares[2] - end of period	83,087,143	83,087,143	83,079,643	83,079,643

[1]See "Non-GAAP" Measures."
[2]All current and comparative share amounts have been adjusted to reflect the two for one common share consolidation completed on May 13, 2014.
[3]Adjusted based on final Old Touchstone purchase price allocation.

Three months ended	December 31, 2014	September 30, 2014	June 30, 2014	March 31, 2014
Operating				
Average daily production[1] *(bbls/d)*	2,283	2,269	1,220	390
Average oil prices before derivatives[1] *($/bbl)*	75.36	92.82	97.09	75.54
Financial *($000's except share and per share amounts)*				
Funds flow from operations[2]	2,247	4,264	(4,007)	(2,114)
Per share – basic and diluted[2,3]	0.03	0.05	(0.06)	(0.04)
Net (loss) earnings	(49,356)[4]	(6,690)	2,751	(3,967)
Per share – basic and diluted[3]	(0.59)	(0.08)	0.04	(0.08)
Capital expenditures				
Exploration assets	504	1,851	3,189	5,811
Property and equipment	9,960	5,834	7,797	19
Acquisitions	-	-	33,448	-
Company total	10,464	7,685	44,434	5,830
Total assets - end of period	140,333[4]	192,637[4]	183,461[4]	92,952
Net surplus[2] - end of period	6,926[4]	1,570[4]	8,754[4]	41,478
Weighted average shares outstanding[3]				
Basic	83,059,643	82,844,988	65,813,486	48,748,337
Diluted	83,059,643	82,844,988	66,069,228	48,748,337
Outstanding shares[3] - end of period	83,059,643	83,059,643	81,738,643	48,787,412

[1]Average daily production and average realized prices include Canadian exploration property results.
[2]See "*Non-GAAP Measures.*"
[3]All current and comparative share amounts have been adjusted to reflect the two for one common share consolidation completed on May 13, 2014.
[4]Adjusted based on final Old Touchstone purchase price allocation.

The Company's funds flow from operations are significantly impacted by changes in production volumes and fluctuations in commodity prices. In addition, net earnings are impacted by asset impairments.

Effective May 13, 2014, the Company completed the acquisition of Old Touchstone. As a result, the Company focused its capital expenditures on the development of the acquired Trinidad onshore oil assets. In addition, working capital diminished as the Company repaid debt acquired with the transaction. On July 1, 2014, the Company determined that the Kerrobert and Luseland producing properties met the criteria for technical feasibility and commercial viability. Accordingly, as of July 1, 2014, all associated revenues, royalties and operating expenses of the two Canadian properties were recognized in the consolidated financial statements. The results of operations relating to these assets were formerly capitalized to exploration assets.

Material Trinidad based impairment charges were recognized in the third quarter of 2015 and the fourth quarter of 2014 related to the sustained decrease in forward commodity prices. In addition, a material impairment charge relating to Canadian segment exploration assets was recognized in the fourth quarter of 2014 due to uneconomic operating results. In response to the decrease in crude oil prices, the Company decreased 2015 capital spending by $30,148,000 or 86% from 2014 levels. Finally, net operating losses and net debt decreased throughout 2015 based on Canadian segment asset dispositions that closed during the year.

Business Risks

For a full understanding of risks that affect the Company, the following should be read in conjunction with the Company's Annual Information Form, which will be available on SEDAR on or before March 30, 2016.

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.

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 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.

Access to capital

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. Internally generated funds will also fluctuate with changing commodity prices.

The borrowing base of the Company's reserve based lending bank loan has been reduced from US$15,000,000 to US$9,000,000 as of the date of this MD&A based on the decline in forward commodity prices. There can be no certainty as to the ability of the Company to successfully restructure its credit facility, or obtain new financing should low crude oil prices persist. There is also no certainty that the revised borrowing base of US$9,000,000 will be re-affirmed during the April 1, 2016 semi-annual borrowing base redetermination.

The Company is required to comply with covenants under this facility, and in the event it does not comply, access to capital could be restricted or repayment may be required. The Company routinely reviews the covenants based on actual and forecasted results and has the ability to make changes to development and exploration plans to comply with the covenants under the bank loan. The Company is committed to having an adaptable capital expenditure program that can be adjusted to capitalize on acquisition opportunities and, if necessary, a tightening of liquidity sources.

Foreign jurisdictions

The Company is currently focused on international oil and gas exploration and production activities in Trinidad. As such, the Company is subject to political risks such as: changes in polices and regulation related to changes in government, price controls, renegotiation of lease operatorship and production license agreements, nationalization, changes in tax and royalty regulations, amendments or changes to legal systems, and complex regulatory regimes. The Company engages local, Canadian and international advisors and local in-country staff to the largest extent possible. The Company is also exposed to potential delay of its operations due to waiting on drilling permits or obtaining surface access to drilling locations. Furthermore, the Company is exposed to foreign exchange fluctuations as noted in "*Risk Management*".

Reserves estimates

The Company has retained an independent engineering consulting firm that assists the Company in evaluating oil and natural gas reserves on an annual basis. Reserve values are based on a number of variables and assumptions such as future commodity prices, future production, future operating and capital costs and governmental regulations. Reserve estimates are prepared in accordance with standards and procedures set out in the Canadian Oil and Gas Evaluation Handbook and NI 51-101. The reserves and recovery information contained in the independent reserve report is an estimate. The actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by the independent reserve engineers. The Company's operational results and financial condition depend on the prices received for petroleum production as noted in "*Risk Management*".

Volatility of commodity prices and foreign exchange rates

The Company's operational results and financial condition depend on the prices received for petroleum production. Commodity prices are determined by economic and, in some circumstances, political factors. Supply and demand factors, including weather and general economic conditions as well as conditions in other oil and natural gas regions, also influence prices. The Company is exposed to commodity price risk whereby the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Petroleum commodity prices are affected by the global economic events that dictate the levels of supply and demand. As at the date of this MD&A, the Company has active crude oil hedges in place (see "*Risk Management – Commodity price risk*").

Foreign currency risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate as a result of changes in foreign currency exchange rates. The Company is exposed to foreign currency fluctuations as various portions of its cash balances, debt balances and future expenses and revenues are denominated in TT$ and US$ (see "*Risk Management - Foreign currency risk*").

Counterparty risk

Credit risk is the risk of a counterparty failing to meet its obligations in accordance with the agreed upon terms. The Company may be exposed to third-party credit risk through its contractual arrangements with its current or future joint operation partners, marketers of its commodities and other parties. Touchstone has established credit policies and controls designed to mitigate the risk of default or non-payment with respect to oil and natural gas sales and financial hedging transactions. However, the Company is exposed to sole purchaser risk in Trinidad as Petrotrin is the sole purchaser of crude oil.

Operational matters

The oil and natural gas industry is intensely competitive, with the Company competing against companies that may have greater technical and financial resources. There is competition for new exploration and development properties, for infrastructure and sales contracts, for drilling and other specialized technical equipment and for experienced key human resources. There are also extensive and varying environmental regulations imposed by the governments in the countries in which the Company operates. The Company adopts prudent and industry-recommended field operating procedures in all of its operations, as well as maintaining a health, safety and environment program in each jurisdiction.

Exploration

The Company is exposed to a high level of exploration risk. The Company's current and future (to the extent discovered or acquired) proved reserves will decline as reserves are produced from its properties unless the Company is able to acquire or develop new reserves. The business of exploring for, developing or acquiring reserves is capital intensive and is subject to numerous estimates and interpretations of geological and geophysical data. There can be no assurance that the Company's future exploration, development and acquisition activities will result in material additions of proved reserves. To manage this risk, to the extent possible, the Company employs highly experienced geologists, uses technology such as 3D seismic as a primary exploration tool and focuses exploration efforts in known hydrocarbon-producing basins. The Company may also choose to mitigate exploration risk through acquisitions that may require raising funds.

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 these estimates. Revisions to these accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgements made by management in the preparation of these consolidated financial statements are outlined below.

Going concern

Management has made judgments relating to future projected cash flows in order to assess the Company's ability to continue as a going concern. These estimates are based upon management's best estimates of future production volumes, forward pricing, future operating and capital costs, exchange rates, interest rates and income taxes, all of which are subject to measurement uncertainty.

As discussed in this MD&A, the Company is awaiting the redetermination of its bank loan and is also seeking alternative sources of financing. There can be no certainty as to the ability of the Company to successfully restructure its credit facility, or obtain new financing should low crude oil prices persist. There is also no certainty that the revised borrowing base of US$9,000,000 will be re-affirmed during the April 1, 2016 semi-annual borrowing base redetermination and accordingly, there is a material uncertainty that may cast significant doubt on the Company’s ability to continue as a going concern.

Oil and natural gas reserves

The Company retains qualified independent reserves evaluators to evaluate the Company’s proved and probable oil and natural gas reserves. As at December 31, 2015, the Company’s reserves were evaluated by GLJ, who is a firm of qualified independent reserves evaluators. The evaluation was conducted in accordance with NI 51-101. The Reserves Committee of the Company’s Board of Directors is comprised of independent directors whose mandate is to steward the reserves evaluation process.

The amounts recorded for exploration assets, property and equipment, depletion and depreciation and impairment testing are based on the reserves estimates, which include estimates of future production rates, oil prices, foreign exchange rates, operating costs, capital costs and other relevant assumptions. Assumptions that are valid at the time of reserves estimation may change significantly when new information becomes available. Changes in forward price estimates, production costs or recovery rates may change the economic status of reserves. Changes in the economic environment could result in significant changes to the discount rate used to calculate net present values. Changes in reserves impact the financial results of the Company as reserves and estimated future development costs are used to calculate depletion and are also used in measuring fair value less costs of disposal of property and equipment for impairment calculations.

As well, the cash-generating unit to which an asset belongs is subject to the judgement of management, and the transfer of exploration assets to property and equipment is based on management’s judgement of technical feasibility and commercial viability.

Business combinations

Business combinations are accounted for using the acquisition method. Under this method, the consideration transferred is allocated to the assets acquired and the liabilities assumed based on the fair values at the time of acquisition. In determining the fair value of the assets and liabilities, management must make assumptions and estimates, such as reserves, future commodity prices, fair value of undeveloped land, discount rates, decommissioning liabilities and possible outcomes of any assumed contingencies.

Decommissioning obligations

The provision for decommissioning obligations is based on numerous assumptions and judgements including the ultimate settlement amounts, inflation factors, risk free discount rates, timing of settlement and changes in the legal and regulatory environments. To the extent future revisions to these assumptions impact the measurement of the existing decommissioning obligation, a corresponding adjustment is made to the property and equipment balance.

Equity-settled transactions

The Company measures the cost of equity-settled transactions by reference to the fair value of the equity instruments at the date at which they are granted. The fair value of share option awards is measured by reference to the five day weighted average trading prices of the common shares prior to the date of the grant. The fair value of share options is measured using a Black-Scholes option pricing model. Measurement inputs include weighted average share prices prior to the measurement date, exercise price of the instrument, expected volatility (based on weighted average historic volatility adjusted for changes expected due to publicly available information), weighted average expected life of the instruments (based on historical experience and general option holder behaviour), expected dividends, and the risk-free interest rate (based on government of Canada bonds).

Fair value of financial derivatives

The fair value of financial derivatives is based on fair values provided by counterparties with whom the transactions are completed. By their nature, these estimates and assumptions are subject to measurement uncertainty.

Income tax accounting

Accounting for income taxes is a complex process requiring management to interpret frequently changing laws and regulations and make judgments relating to the application of tax law, the estimated timing of temporary difference reversals, and the estimated realization of tax assets. All tax filings are subject to subsequent government audits and potential reassessment. These interpretations, judgments and changes related to them impact current and deferred tax provisions, deferred income tax assets and liabilities and net earnings.

Legal and other contingent matters

In respect of these matters, the Company is required to determine both whether a loss is probable based on judgment and interpretation of laws and regulations and if such a loss can reasonably be estimated. When any such loss is determined, it is charged to net earnings. Management continually monitors known and potential contingent matters and makes appropriate provisions by charges to net earnings when warranted by circumstances.

Adoption of new accounting policies

There were no new or amended accounting standards or interpretations adopted by the Company during the year ended December 31, 2015.

Future changes in accounting policies

The Company will be required to adopt IFRS 9 *Financial Instruments* on January 1, 2018, IFRS 11 *Joint Arrangements* on January 1, 2016, IFRS 15 *Revenue from Contracts with Customers* on January 1, 2018 and IFRS 16 *Leases* on January 1, 2019. The Company continues to assess the impact of adopting these pronouncements.

Control Environment

Management, including the Company's President and Chief Executive Officer and Chief Financial Officer, has assessed the design and effectiveness of internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P") as at December 31, 2015. In making its assessment, Management used the Committee of Sponsoring Organizations of the Treadway Commission Framework in Internal Control – Integrated Framework (2013) to evaluate the design and effectiveness of internal control over financial reporting. Based on the Company's evaluation, Management has concluded that both ICFR and DC&P were effective as at December 31, 2015.

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. Also, 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.

Advisory on Reserves Information

The reserves information summarized in this MD&A is from reports prepared by Touchstone's independent reserves evaluator, GLJ, dated March 8, 2016 with an effective date of December 31, 2015 and dated March 11, 2015 with an effective date of December 31, 2014. Each of these reports were prepared in accordance with definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook and NI 51-101. All December 31, 2015 reserves presented are based on GLJ's forecast pricing and estimated costs effective January 1, 2016, and December 31, 2014 reserves presented are based on GLJ's forecast prices and estimates of future costs as at January 1, 2015. Additional reserves information as required under NI 51-101 will be included in the Company's Annual Information Form which will be filed on SEDAR on or before March 30, 2016.

This MD&A contains certain oil and gas metrics, including finding and development costs, reserves replacement ratio and reserves additions, which do not have standardized meanings or standardized methods of calculation and therefore such measures may not be comparable to similar measures presented by other companies. Such metrics have been included herein to provide readers with additional metrics to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance of the Company, and future performance may not compare to the performance in prior periods and therefore such metrics should not be unduly relied upon.

Trinidad based finding and development costs are the sum of total Trinidad segment capital expenditures incurred in the period and the change in future development costs required to develop those reserves. Finding and development costs per barrel is determined by dividing current period net reserve additions to the corresponding period's finding and development cost. Reserve additions are calculated as the change in reserves from the beginning to the end of the applicable period excluding period production. Reserves replacement ratio is calculated as reserve additions divided by period production. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year. The Company uses finding and development costs as a measure of the efficiency of its overall capital program. Management uses finding and development cost metrics for its own performance measurements and to provide shareholders with measures to compare the Company's operations over time.

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", "targeting", "intend", "could", "might", "should", "believe" and other similar expressions. Statements relating to "reserves" and "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future. Such statements represent the Company's internal projections, estimates or beliefs concerning future growth, results of operations based on information currently available to the Company based on assumptions that are subject to change and are beyond the Company's control, such as: production rates and production decline rates, the magnitude of and ability to recover oil and gas reserves, plans for and results of drilling activity, well abandonment costs and salvage value, 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, among other things. 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. In particular, forward-looking statements contained in this MD&A include, but are not limited to, statements with respect to:

- the Company's operational strategy, including targeted jurisdictions and technologies used to execute its strategy;
- the Company's ability to continue to operate as a going concern;
- activities to be undertaken in various areas including the fulfillment of minimum work obligations and exploration commitments;
- terms of exploration and production contracts and the expected renewal of certain contracts;
- foreign currency risk and the ability to reverse unrealized foreign exchange gains and losses in the future;
- the Company's risk management strategy and the use of commodity derivatives to manage movements in the price of crude oil;
- the Company's position related to its Trinidad uncertain tax positions;
- the Company's expected completion of the sale of its East Brighton exploration property;
- the Company's expected future credit facility borrowing base and future sources of liquidity;
- terms of the Company's contractual commitments and their timing of settlement;
- 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*."

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 oil reserves on an economic basis and the potential for technical problems that could lead to well blowouts 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 including 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 oil, the impact of significant declines 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 oil and gas industry, fluctuations in interest rates, the Canadian dollar to United States dollar exchange rate and the Canadian dollar to Trinidad and Tobago dollar exchange rate. 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, lease operating or farm-in rights related to the Company's oil and gas interests in Trinidad.

Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and as such, undue reliance should not be placed on forward-looking statements. Readers are also cautioned that the foregoing list of factors and assumptions is not exhaustive. The Company does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws. Additional information on these and other factors that could affect the Company's operations and financial results are included elsewhere herein and in reports, documents and disclosures on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com).

Non-GAAP Measures

The MD&A contains terms commonly used in the oil and natural gas industry, including funds flow from operations, funds flow from operations per share, operating netback, funds flow 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.

The following table reconciles funds flow from operations to cash flows from operating activities, which is the most direct comparable measure calculated in accordance with IFRS:

($000's)	**Year ended December 31,**	
	2015	2014
Cash flows from operating activities	**(3,245)**	4,039
Changes in non-cash working capital	**6,153**	(3,649)
Funds flow from operations	**2,908**	390

Management believes that in addition to net earnings and cash flows from operating activities, funds flow from operations is a useful financial measurement which assists in demonstrating the Company's ability to fund capital expenditures necessary for future growth or to repay debt. The Company's determination of funds flow from operations may not be comparable to that reported by other companies. All references to funds flow from operations throughout this MD&A are based on cash flow from operating activities before changes in non-cash working capital. 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 funds flow netbacks as a key performance indicator of results. Funds flow netbacks do not have a standardized meaning under IFRS and therefore may not be comparable with the calculation of similar measures by other companies. Funds flow netbacks are presented on a per barrel basis and are calculated by deducting royalties, operating expenses, general and administrative expenses, net cash finance expenses and current income tax expenses from petroleum revenue and realized gains/losses on derivative contracts. Funds flow netbacks are a useful measure to compare the Company's operations with those of its peers. Net cash finance expenses include all cash finance expenses incurred during a period and exclude the amortization of prepaid bank loan fees.

The Company also uses operating netbacks as a key performance indicator of field results. Operating netbacks do not have a standardized meaning under IFRS and therefore may not be comparable with the calculation of similar measures by other companies. Operating netbacks are presented on a per barrel basis and are calculated by deducting royalties and operating expenses from petroleum revenue and realized gains/losses on derivative contracts. The Company considers operating netbacks to be a key measure as they demonstrate Touchstone's profitability relative to current commodity prices.
The following table summarizes net (surplus) debt:

	As at December 31,	
($000's)	**2015**	2014
Working capital (surplus) deficiency	**(987)**	1,289
Add current portion of finance lease obligations and other	**-**	(510)
Long-term portion of bank loan	**-**	5,800
Less finance lease obligations	**-**	347
Net (surplus) debt	**(987)**	6,926

Net (surplus) debt is calculated by summing the Company's working capital and non-current interest bearing liabilities. Working capital is defined as current assets less current liabilities. The Company uses this information to assess its true debt and liquidity position and to manage capital risk. This measure does not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures reported by other companies.

Currency and References to Touchstone

All information included in this MD&A are 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 on-line on SEDAR at www.sedar.com or from the Company's website at www.touchstoneexploration.com.

CORPORATE INFORMATION

DIRECTORS

John Wright[3]
Chairman of the Board

Paul R. Baay

Kenneth McKinnon[1,2]

Trevor Mitzel[1,2]

Corey Ruttan[1,3]

Thomas Valentine[4]

Harrie Vredenburg[2,3]

Member of:
[1] Audit Committee
[2] Compensation Committee
[3] Reserve Committee
[4] Corporate Secretary

OFFICERS AND KEY PERSONNEL

Paul R. Baay
President and Chief Executive Officer

Scott Budau
Chief Financial Officer

James Shipka
Chief Operating Officer

Michael Loewen
Trinidad Country Manager

Andrea Hatzinikolas
Assistant Corporate Secretary

HEAD OFFICE

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BANKERS

The Bank of Nova Scotia
Houston, USA
Port of Spain, Trinidad

AUDITORS

Ernst and Young LLP
Calgary, Alberta
Port of Spain, Trinidad

RESERVE EVALUATORS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL

Norton Rose Fulbright Canada LLP
Calgary, Alberta

LEX Caribbean
Port of Spain, Trinidad

TRANSFER AGENT AND REGISTRAR

Computershare Trust Company of Canada
Calgary, Alberta

ABBREVIATIONS

Oil

bbls	barrels
Mbbls	thousand barrels
bbls/d	barrels per day
boe	barrels of oil equivalent
Mboe	thousand barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Brent	The reference price paid for crude oil FOB North Sea
LIBOR	London Interbank Offered Rate
WCS	Western Canada Select heavy oil
WTI	Western Texas Intermediate, the reference price paid for crude oil and standard grade in U.S. dollars at Cushing Oklahoma

Other

C$	Canadian dollar
US$	United States dollar
TT$	Trinidad and Tobago dollar
TSX	Toronto Stock Exchange