Touchstone Exploration Inc.

Management's Discussion and Analysis

December 31, 2021

Management's Discussion and Analysis
As at and for the three months and years ended December 31, 2021 and 2020

This Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of Touchstone Exploration Inc. ("Touchstone", "we", "our", "us" or the "Company") for the three months and year ended December 31, 2021 with comparisons to the three months and year ended December 31, 2020 is dated March 25, 2022 and should be read in conjunction with the Company's audited consolidated financial statements as at and for the years ended December 31, 2021 and 2020 (the "audited financial statements") and our 2021 Annual Information Form. The audited financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board.

Unless otherwise stated, all financial amounts presented herein are rounded to thousands of United States dollars ("$" or "US$").

The Company may also reference Canadian dollars ("C$") and Trinidad and Tobago dollars ("TT$") herein, which are the functional and operational currencies of the Company's parent company and operating subsidiaries, respectively. All production volumes disclosed herein are sales volumes and are based on Company working interest before royalty burdens. Certain prior year amounts have been reclassified to conform to current year presentation.

Certain measures in this MD&A do not have any standardized meaning prescribed under IFRS and therefore are considered non-GAAP financial measures. Readers are cautioned that this MD&A should be read in conjunction with Touchstone's disclosure under the "*Advisory*" section herein which provides information on non-GAAP financial measures, forward-looking statements, oil and natural gas reserves, oil and natural gas measures and references to Touchstone.

About Touchstone Exploration Inc.

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

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

Additional Information

Additional information related to Touchstone and factors that could affect the Company's operations and financial results are included with reports on file with the Canadian securities regulatory authorities, including the Company's 2021 Annual Information Form dated March 25, 2022, which can be accessed online on the Company's SEDAR profile at www.sedar.com or from the Company's website at www.touchstoneexploration.com.

Financial and Operating Results Summary

	Three months ended December 31, 2021	2020	% change	Year ended December 31, 2021	2020	% change
Operational						
Average daily oil production[1] *(bbls/d)*	**1,336**	1,274	5	**1,342**	1,392	(4)
Net wells drilled	**3.0**	1.6	88	**3.8**	1.6	100
Brent benchmark price *($/bbl)*	**79.61**	44.32	80	**70.86**	41.96	69
Operating netback[2] *($/bbl)*						
Realized sales price	**66.81**	37.66	77	**60.25**	38.34	57
Royalties	**(22.15)**	(10.48)	100	**(18.85)**	(10.74)	76
Operating expenses	**(14.70)**	(13.28)	11	**(14.85)**	(13.11)	13
Operating netback	**29.96**	13.90	100	**26.55**	14.49	83
Financial *($000's except per share amounts)*						
Petroleum sales	**8,212**	4,414	86	**29,568**	19,592	51
Cash from operating activities	**1,388**	167	100	**1,546**	2,296	(33)
Funds flow from (used in) operations	**1,291**	(736)	n/a	**4,107**	263	100
Per share – basic and diluted[2]	**0.01**	(0.00)	n/a	**0.02**	0.00	n/a
Net earnings (loss)	**6,514**	1,655	100	**5,719**	(11,030)	n/a
Per share – basic and diluted	**0.03**	0.01	100	**0.03**	(0.06)	n/a
Exploration capital expenditures	**2,946**	9,031	(67)	**20,106**	17,861	13
Development capital expenditures	**5,190**	186	100	**7,757**	709	100
Total capital expenditures	**8,136**	9,217	(12)	**27,863**	18,570	50
Working capital surplus[2]				**(6,925)**	(12,933)	(46)
Principal long-term balance of term loan				**27,000**	7,500	100
Net debt (surplus)[2] – end of period				**20,075**	(5,433)	n/a
Share Information *(000's)*						
Weighted average – basic	**210,732**	197,686	7	**210,160**	183,781	14
Weighted average – diluted	**218,102**	206,072	6	**217,678**	183,781	18
Outstanding shares – end of period				**210,732**	209,400	1

Notes:
(1) The Company's reported crude oil production is a mix of light and medium crude oil and heavy crude oil for which there is not a precise breakdown since the Company's oil sales volumes typically represent blends of more than one type of crude oil.
(2) Non-GAAP financial measure. See the "*Non-GAAP Financial Measures*" advisory section of this MD&A for further information.

Fourth Quarter 2021 Highlights

- Achieved quarterly average production volumes of 1,336 bbls/d, representing a 5 percent increase from 1,274 bbls/d produced in the fourth quarter of 2020.
- Realized petroleum sales of $8,212,000 from an average crude oil price of $66.81 per barrel compared to petroleum sales of $7,650,000 from average realized pricing of $62.37 per barrel in the third quarter of 2021.
- Generated an operating netback of $29.96 per barrel, an 8 percent increase from the third quarter of 2021 and a 116 percent increase from the $13.90 per barrel in the fourth quarter of 2020.
- Our funds flow from operations improved to $1,291,000 in the quarter compared to funds flow used in operations of $736,000 in the fourth quarter of 2020.

- Reported net earnings of $6,514,000 ($0.03 per basic and diluted share) compared to net earnings of $1,655,000 ($0.01 per basic and diluted share) in the same period of 2020. Net earnings in the fourth quarter included net impairment reversals of $13,716,000, partially offset by associated deferred income tax expenses of $7,226,000.
- Exploration and evaluation capital investments of $2,946,000 focused on completing and initiating production testing operations on the Royston-1 well drilled in the third quarter of 2021 and submitting the required regulatory application for the Cascadura surface facility.
- Drilled three gross and net commitment wells on our legacy crude oil properties in the quarter, representing our first infill development drilling since 2019.
- Expanded our Trinidad-based term loan facility from $20 million to $30 million to fund our budgeted Ortoire facility projects in 2022. We exited the year with cash of $17,936,000, working capital surplus of $6,925,000 and $30,000,000 drawn on our term credit facility, resulting in a net debt position of $20,075,000.

Annual 2021 Highlights

- Reported average daily crude oil sales of 1,342 bbls/d in 2021, a nominal 4 percent decrease relative to the 1,392 bbls/d produced in 2020 due to natural declines, reflecting strategic capital allocation on our Ortoire exploration program. Production from our three development wells drilled in the fourth quarter of 2021 came online in the first quarter of 2022.
- Generated funds flow from operations of $4,107,000 (2020 - $263,000) and an annual operating netback of $26.55 per barrel (2020 - $14.49 per barrel).
- Recognized net earnings of $5,719,000 ($0.03 per basic and diluted share) compared to a net loss of $11,030,000 ($0.06 per basic share) in 2020, driven by $13,674,000 in net impairment reversals recognized in the year predominantly based on increased forecasted crude oil pricing and partially offset by the deferred income tax expense impact of $7,463,000.
- Despite COVID-19 challenges in Trinidad, we executed an incident-free $20,106,000 exploration program, primarily focused on drilling one gross (0.8 net) well, acquiring 22-line kilometres of 2D seismic and testing two exploration wells drilled in 2020. We fulfilled all required minimum work obligations in the initial exploration period of our Ortoire exploration and production licence.
- Development capital expenditures of $7,757,000 focused on exporting a third-party drilling rig to Trinidad, which was used to drill three development wells in the fourth quarter of 2021.
- Entered into revised ten-year lease operating agreements for our Coora-1, Coora-2, WD-4 and WD-8 blocks through December 31, 2030.

Recent Highlights

- Daily crude oil sales averaged 1,382 bbls/d in January 2022 with a realized price of $71.68 per barrel and averaged 1,384 bbls/d in February 2022 with a realized price of $81.30 per barrel.
- In February 2022, we executed the relevant agreements with our third-party partners to allow for the final tie-in of the Coho gas field, with pipeline tie-in operations proceeding.
- On March 7, 2022, we announced the results of our December 31, 2021 reserves evaluation, highlighted by an increase of gross proved plus probable ("2P") reserves of 16% to 75,547 Mboe and an increase in gross proved ("1P") reserves by 13% to 38,731 Mboe from December 31, 2020. The reserves data is based on an independent reserve evaluation prepared by GLJ Ltd. ("GLJ") dated March 4, 2022 with an effective date of December 31, 2021 (the "Reserves Report").
- In March 2022, we were notified that the Trinidad government approved a five-year extension to the exploration period of our Ortoire licence to July 31, 2026 for an additional three exploration well commitment.

Principal Properties and Licences

We hold interests in producing and exploration properties in southern Trinidad and minimal undeveloped acreage in Saskatchewan, Canada. Touchstone operates all properties apart from the Cory Moruga exploration block. A schedule of our core Trinidad property interests as of December 31, 2021 is set forth below.

Property	Working interest (%)	Licence type	Gross acres(1)	Net acres(2)
Developed				
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
Barrackpore	100	Private	211	211
Fyzabad	100	Crown and Private	564	564
Ortoire - Coho	80	Crown	1,317	1,054
San Francique	100	Private	1,277	1,277
	96		**6,418**	**6,155**
Exploratory				
Ortoire	**80**	Crown	**43,414**	**34,731**
Total	**82**		**49,832**	**40,886**

Notes:
(1) "Gross" means acres in which the Company has an interest.
(2) "Net" means the Company's interest in the gross acres.

Touchstone operates Trinidad-based upstream oil and natural gas activities under state exploration and production licences with the Trinidad and Tobago Ministry of Energy and Energy Industries ("MEEI"), Lease Operatorship Agreements ("LOAs") with Heritage Petroleum Company Limited ("Heritage") and private subsurface and surface leases with individual landowners. The LOAs contain marketing arrangements, whereas any oil sold from MEEI licences and private agreements are marketed under a separate Heritage crude oil sales agreement. In addition, we executed a long-term natural gas sales agreement with the National Gas Company of Trinidad and Tobago ("NGC") related to all future natural gas sales from our Ortoire property in December 2020.

MEEI exploration and production licences

The Company is party to exploration and production licences with the MEEI for our Fyzabad producing property and our Cory Moruga and Ortoire exploration fields. The licences typically are for an initial six-year term, with the option to extend certain acreage a further 19 years upon an approved commercial discovery. Our Fyzabad exploration and production licence contains no minimum work obligations and expires in August 2032. We hold a non-operating 16.2 percent interest in the Cory Moruga exploration block which we consider non-core. Our core focus is the Ortoire exploration block (refer to "*Ortoire Operations*" for further details).

Lease operatorship agreements

In June 2021, we executed ten-year LOAs with Heritage for our Coora-1, Coora-2, WD-4 and WD-8 blocks effective January 1, 2021. The LOAs were renewed under substantially similar terms to the previous arrangements.

Under the new arrangements, we are subject to annual minimum production levels and minimum work commitments from 2021 through 2030 specified under each LOA. Failing to reach either the annual minimum production levels or complete the annual minimum work obligations will not constitute a breach provided the minimal production levels have been attained or the minimum work obligations have been completed, as the case may be. The LOAs contain an aggregate minimum of 20 new infill wells and 40 well recompletions to be completed over the ten-year licence periods.

The following table sets forth information relating to our producing properties governed by LOAs as of December 31, 2021.

Field	Current licence expiry	Carrying value(1) ($000's)	Gross 1P reserves(2) (Mbbls)	Gross 2P reserves(2) (Mbbls)	Minimum work commitments(3) ($000's)
Coora(4)	December 31, 2030(5)	15,384	3,238	5,107	14,130
WD-4	December 31, 2030(5)	18,359	2,856	5,270	4,360
WD-8	December 31, 2030(5)	15,899	2,552	4,867	4,430
Total		**49,642**	**8,646**	**15,244**	**22,920**

Notes:

(1) Represents the field's carrying value included in property, plant and equipment ("PP&E") as at December 31, 2021.

(2) December 31, 2021 assigned gross crude oil reserves are the Company's working interest share before deduction of royalties. Refer to the "*Oil and Natural Gas Reserves*" advisory section of this MD&A.

(3) Includes future estimates of minimum work obligations stipulated in the LOA as of December 31, 2021 (refer to "*Contractual Obligations and Commitments* " for further details).

(4) The Coora field is governed by the Coora-1 and Coora-2 LOAs.

(5) The LOAs may be extended for a further five-year term pending mutual agreement to minimum work commitments over the extended period.

Private lease agreements

Touchstone may also negotiate private surface and subsurface lease arrangements with individual landowners. Lease terms are typically 35 years in duration and contain no minimum work obligations. The Company is operating under a number of Trinidad private lease agreements which have expired and are currently being renewed. Based on legal opinions received, Touchstone is continuing to recognize petroleum sales on the producing properties because the Company is the operator, is paying all associated royalties and taxes, and no title to the producing properties has been disputed. The continuation of production from expired private leases during the renegotiation process is common in Trinidad based on antiquated land title processes. During the year ended December 31, 2021, production volumes produced under expired private lease agreements represented 1.9 percent of our total production (2020 - 1.8 percent).

Crude oil marketing agreements

On January 14, 1974, Premier Consolidated Oilfields Limited, the Company's predecessor in interest, and Texaco Trinidad Inc., Heritage's predecessor, entered into a Crude Oil Purchase Agreement whereby Texaco Trinidad Inc. committed to purchase all crude oil produced by our wholly-owned Trinidad subsidiary, Primera Oil and Gas Limited ("POGL"), from various producing properties operating under MEEI licences and private lease agreements. The agreement was novated to Heritage on December 1, 2018. The agreement, as amended from time to time, has continued to have an indefinite term and may be terminated by either party upon three months' notice. The price currently paid is Heritage's equity land blend indexed price, payable in US$. In January 2022, the parties executed a letter agreement to sell testing production volumes produced from the Royston-1 exploration well under similar terms and conditions.

Natural gas sales contract

On December 18, 2020, POGL and NGC executed a natural gas sales agreement for all future natural gas production from our Ortoire block. Future natural gas sales are based on a fixed US$ price per MMBtu, with an annual inflation escalator. The parties may renegotiate the natural gas sales price on each fifth anniversary of the initial production date. POGL shall deliver all future natural gas production at the edge of the specific well site battery, with title, risk of loss and other customary matters dealt with at the delivery point, thereby eliminating transportation and processing charges. Payment terms are industry standard and shall be paid in US$ on a monthly basis. Any potential free liquids associated with future natural gas production on the Ortoire block are expected to be marketed by POGL under a separate arrangement.

Ortoire Operations

Licence

Effective October 31, 2014, POGL entered into an 80 percent operating working interest in the Ortoire exploration and production licence (the "Ortoire Licence") with the MEEI and Heritage, with Heritage holding the remaining 20 percent working interest. The Ortoire Licence was originally effective for an initial term of six years, under which any approved commercial discovery can be extended for a further 19 years. In March 2021, the parties amended the Ortoire Licence to extend the initial exploration period an additional nine months through July 31, 2021, during which we completed all required exploration minimum work commitments.

In March 2022 we were notified by the MEEI that the Trinidad government approved an extension of the exploration period of the Ortoire Licence to July 31, 2026. As part of the extension, we are required to drill three additional exploration wells to minimum depths of 6,000 true vertical feet prior to the end of the amended Ortoire Licence term. Similar to the initial minimum work program, we will be responsible for 100 percent of the drilling, completion and testing costs for the three additional wells. Each party to the Ortoire Licence remains responsible for its working interest costs associated with the development of commercial fields, including expenditures relating to facilities construction and development well drilling.

The Ortoire Licence extension will allow us to continue exploration operations on acreage that have not yet been approved as commercial, and no acreage was surrendered pursuant to the extension. The Ortoire Licence amendment agreement is currently required to be approved by the Office of the Attorney General and Ministry of Legal Affairs prior to execution by all parties.

The following table sets forth Touchstone's aggregate Ortoire exploration and evaluation ("E&E") investments as of December 31, 2021 and 2020.

($000's)	**December 31, 2021**	**December 31, 2020**
Coho-1 drilling and testing	**3,768**	3,587
Coho-1 facility and pipeline	**2,092**	1,155
Cascadura-1ST1 drilling and testing	**6,538**	6,557
Cascadura Deep-1 drilling and testing	**7,048**	5,656
Cascadura facility and pipeline	**288**	2
Cascadura environmental impact study	**334**	-
Chinook-1 drilling and testing	**8,857**	7,093
Royston-1 drilling	**10,049**	166
Seismic program	**3,138**	513
Drilling inventory	**1,377**	-
Ortoire Licence financial obligations	**3,937**	3,021
Other	**3,334**	2,930
Total Ortoire E&E investments	**50,760**	**30,680**

Touchstone has conducted exploration activities in four areas within the Ortoire Licence to date: Coho, Cascadura, Chinook and Royston.

Coho

In February 2021, the MEEI approved our field development plan for the Coho area, which extends the exploration and production period for the defined 1,317-acre area through October 31, 2039.

All of the required agreements with our third-party partners to allow for the final tie-in of the Coho gas field to the third-party Central Block Baraka natural gas facility have been executed. Pipeline installation operations have commenced with first gas anticipated in May 2022 subject to weather delays.

The following table sets forth information relating to the Coho area as of December 31, 2021.

Field	Current licence expiry	Carrying value(1) ($000's)	Gross 1P reserves(2) (Mboe)	Gross 2P reserves(2) (Mboe)	Minimum work commitments ($000's)
Coho	October 31, 2039	6,872	1,184	3,454	-

Notes:
(1) Represents the field's carrying value included in E&E assets as at December 31, 2021 including allocated overhead charges.
(2) December 31, 2021 assigned gross natural gas reserves are the Company's working interest share before deduction of royalties. Refer to the "*Oil and Natural Gas Reserves*" and the "*Oil and Natural Gas Measures*" advisory sections of this MD&A.

Cascadura

We have completed the design of the surface facilities required to meet the initial and long-term production capabilities of the Cascadura-1ST1 and Cascadura Deep-1 exploration wells that have been successfully tested. The Cascadura surface facility is designed with a maximum production capacity of 200 MMcf/d of natural gas and 5,000 bbls/d of NGL production from both existing wells and any potential production from the expected future development of the Cascadura B and C locations. Further, the project includes an 8.3-kilometre liquids pipeline that runs south from the surface facility to the Heritage Catshill manifold. The facility is proceeding with the major facility components nearing completion for transportation to Trinidad. The components will be delivered on skids and will be assembled in the field by local contractors.

In parallel with the facilities procurement and construction, we have submitted the required regulatory environmental application and expect to receive a response on or before mid-May 2022. Upon approval, we expect to immediately proceed with construction of the surface facility, as well as required road construction and the construction of future development drilling locations.

The following table sets forth information relating to the Cascadura field as of December 31, 2021.

Field	Current licence expiry	Carrying value(1) ($000's)	Gross 1P reserves(2) (Mboe)	Gross 2P reserves(2) (Mboe)	Minimum work commitments ($000's)
Cascadura	October 31, 2039(3)	16,661	26,902	52,082	-

Notes:
(1) Represents the field's carrying value included in E&E assets as at December 31, 2021 including allocated overhead charges.
(2) December 31, 2021 assigned gross natural gas and NGL reserves are the Company's working interest share before deduction of royalties. Refer to the "*Oil and Natural Gas Reserves*" advisory section of this MD&A.
(3) The Company has submitted a declaration of commerciality and field development plan to the MEEI for the Cascadura gross 2,378-acre area. Upon expected approval, the licence area defined by the MEEI will be extended to October 31, 2039.

Chinook

The Chinook-1 exploration well was drilled in the second half of 2020, with four subsequent production tests suggesting the various reservoirs tested in the well contained hydrocarbons that are uneconomic to produce. However, seismic data and offsetting well data indicate future drilling opportunities in the area that are geologically situated up structure from the Chinook-1 well. We have submitted a notification of commercial potential for the Chinook area to the MEEI and are currently drafting declaration of commerciality and comprehensive field development submissions.

Royston

The Royston-1 exploration well was drilled in the third quarter of 2021 to a total depth of 10,700 feet, representing the deepest exploration well drilled by Touchstone to date. We commenced a long-term production test of the uppermost 84 feet of the Herrera overthrust section in January 2022 with the goal of evaluating different flowing regimes and possible pump configurations to maximize oil production. While conducting the test, approximately 2,200 feet of pipe and perforating guns were stuck in the bottom portion of the well, not allowing any further testing of the deeper zones. Despite these constraints, the well has continued to deliver both pumping and flowing volumes from the uppermost 84 feet.

Combined with the previous test in the intermediate zone, the well has shown that the completed intervals are capable of producing over 675 bbls/d of crude oil. Produced oil is being sold in 2022 at our Barrackpore sales facility, and we anticipate continuing the extended production test until the commencement of future drilling operations at Royston.

We completed our 2D seismic program work commitment in the Royston area in the third quarter of 2021. Four northwest to southeast oriented lines were acquired totalling 22 kilometres in length. The Ortoire 2D seismic dataset was processed with an overlap of the Rio Claro block 2D lines, which produced a high-quality merged product with signal to noise ratios up to four times better than previous 2D surveys completed in Trinidad. Seismic products have been interpreted at both the Mid Miocene and Cretaceous intervals, producing higher resolution structural maps with a greater degree of confidence over the Royston, Steelhead and Bass structures at Mid Miocene, and over the Kraken prospect at the Cretaceous level.

The following table sets forth information relating to the Royston area as of December 31, 2021.

Field	**Current licence expiry**	**Carrying value[1]** *($000's)*	**Gross 1P reserves[2]** *(Mbbls)*	**Gross 2P reserves[2]** *(Mbbls)*	**Minimum work commitments** *($000's)*
Royston	To be determined[3]	15,464	1,280	3,520	-

Notes:
(1) Represents the field's carrying value included in E&E assets as at December 31, 2021 including allocated overhead charges.
(2) December 31, 2021 assigned gross crude oil reserves are the Company's working interest share before deduction of royalties. Refer to the "*Oil and Natural Gas Reserves*" advisory section of this MD&A.
(3) The Company is currently drafting a declaration of commerciality and field development plan to the MEEI for the Royston commercial discovery.

Results of Operations

Financial highlights

($000's except for per share amounts)	**Three months ended December 31,**		% change	**Year ended December 31,**		% change
	2021	2020		**2021**	2020	
Net earnings (loss)	**6,514**	1,655	100	**5,719**	(11,030)	n/a
Per share – basic and diluted	**0.03**	0.01	100	**0.03**	(0.06)	n/a
Cash from operating activities	**1,388**	167	100	**1,546**	2,296	(33)
Funds flow from (used in) operations	**1,291**	(736)	n/a	**4,107**	263	100
Per share – basic and diluted[1]	**0.01**	(0.00)	n/a	**0.02**	0.00	n/a

Note:
(1) Non-GAAP financial measure. See the "*Non-GAAP Financial Measures*" advisory section of this MD&A for further information.

Net earnings (loss)

Touchstone recorded net earnings of $6,514,000 ($0.03 per basic and diluted share) in the fourth quarter of 2021 compared to $1,655,000 ($0.01 per basic and diluted share) in the prior year equivalent quarter. Compared to the fourth quarter of 2020, the variance reflected an increase of $5,868,000 in impairment reversals, slightly offset by an increase in deferred income taxes of $3,370,000. Further increases in fourth quarter 2021 net earnings from the comparative quarter of 2020 were attributed to an increase of

$2,052,000 in operating netbacks based on increased realized pricing.

We recognized net earnings of $5,719,000 ($0.03 per basic and diluted share) in 2021 versus a net loss of $11,030,000 ($0.06 per basic share) in 2020. Compared to 2020, the variance was mainly a result of net impairment reversals recorded in 2021 versus net impairments recognized in the 2020 financial year. Prior year PP&E impairments of $10,623,000 were recognized due to crude oil price forecasts deteriorating from decreases in demand as a result of the onset of the novel coronavirus ("COVID-19") pandemic, which were partially offset by $6,273,000 in related deferred income tax recoveries. A rebound in crude oil prices and increased field activity in 2021 led to a PP&E impairment reversal of $13,786,000, offset by the deferred income tax impact of $7,463,000. In addition, 2021 operating netbacks increased by $5,625,000 in comparison to 2020, reflecting increased realized pricing received throughout 2021, slightly offset by increased royalty expenses.

Details of the change in net earnings (loss) from the three months and year ended December 31, 2020 to the three months and year ended December 31, 2021 are included in the table below.

($000's)	**Three months ended December 31,**	**Year ended December 31,**
Net earnings (loss) – 2020	1,655	(11,030)
Realized price variance	**3,583**	**10,755**
Sales volume variance	**215**	**(779)**
Royalties	**(1,495)**	**(3,763)**
Other revenue	**(25)**	**(81)**
Expenses		
Operating	**(251)**	**(588)**
General and administration	**803**	**(727)**
Cash finance	**(68)**	**520**
Current income tax	**(273)**	**(1,084)**
Realized foreign exchange	**(462)**	**(400)**
Total cash variances	**2,027**	**3,853**
Gain on asset dispositions	**-**	**21**
Unrealized foreign exchange	**394**	**238**
Equity-based compensation	**(225)**	**(586)**
Depletion and depreciation	**(245)**	**89**
Impairment	**5,868**	**25,092**
Non-cash finance expenses	**410**	**1,778**
Deferred income tax	**(3,370)**	**(13,736)**
Total non-cash variances	**2,832**	**12,896**
Net earnings – 2021	**6,514**	**5,719**

Cash from operating activities

Details of the change in cash from operating activities from the three months and year ended December 31, 2020 to the three months and year ended December 31, 2021 are included in the table below.

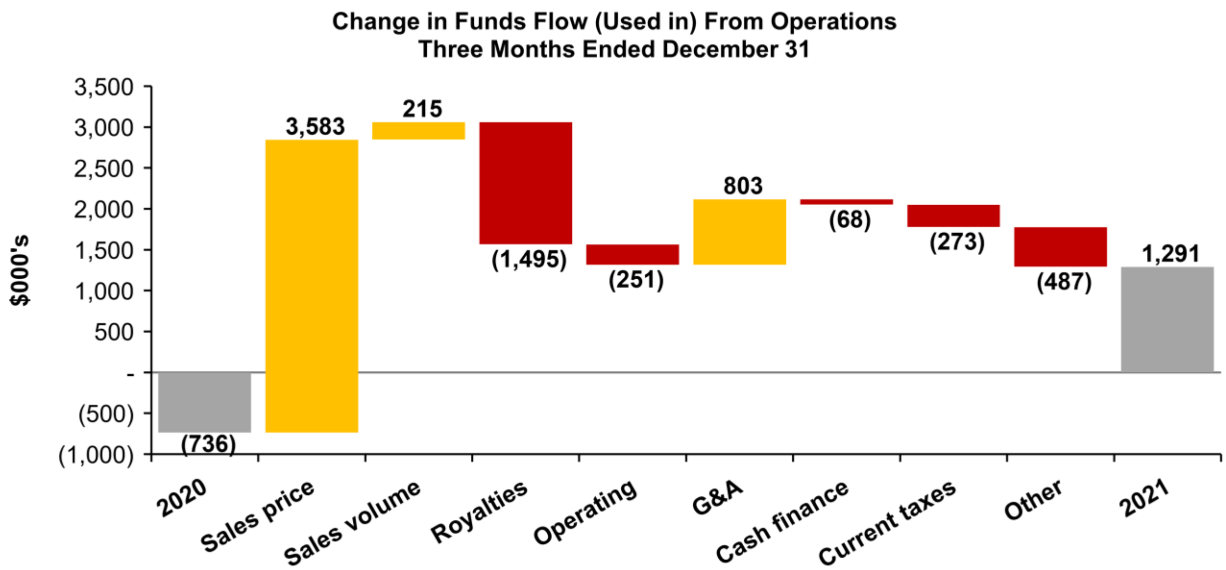
($000's)	**Three months ended December 31,**	**Year ended December 31,**
Cash from operating activities – 2020	167	2,296
Increase in funds flow from operations	**2,027**	**3,844**
Net change in non-cash working capital	**(806)**	**(4,594)**
Cash from operating activities – 2021	**1,388**	**1,546**

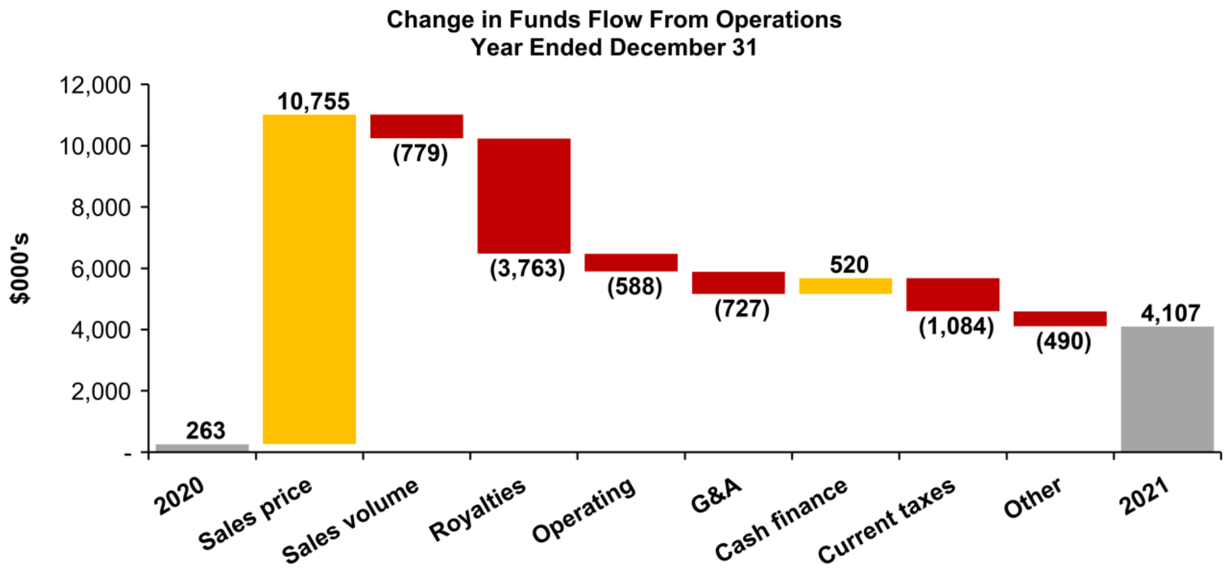
Funds flow from operations

Touchstone generated funds flow from operations of $1,291,000 in the fourth quarter of 2021 compared to funds flow used in operations of $736,000 in the prior year comparative quarter. The increase from the prior year period primarily reflected elevated crude oil realized pricing, which increased 2021 fourth quarter operating netbacks by $2,052,000 from 2020.

During the year ended December 31, 2021, we generated funds flow from operations of $4,107,000, representing a $3,844,000 increase relative to the $263,000 recognized in 2020. In comparison to 2020, increased operating netbacks of $5,625,000 and cash finance expense savings of $520,000 achieved in 2021 were partially offset by increased general and administration ("G&A") and current income tax expenses.

The following graphs summarize the change in funds flow from operations from the three months and year ended December 31, 2020 to the three months and year ended December 31, 2021.





Net loss and funds flow from operations sensitivity

The following table illustrates sensitivities of operating items to operational and business environment changes and the resulting estimated impact to net earnings and funds flow from operations for the year ended December 31, 2021.

	Assumption(1)	**Change**	**Impact on annual net earnings**(2) *($000's)*	**Impact on annual funds flow from operations**(2) *($000's)*
Average realized price *($/bbl)*	60.25	10%	**1,050**	**1,725**
Average production volumes *(bbls/d)*	1,344	10%	**957**	**1,573**
Operating expenses *($/bbl)(3)*	14.85	10%	**(420)**	**(631)**

Notes:
(1) Assumptions are indicative of actual prices and volumes realized and actual results for the year ended December 31, 2021.
(2) Calculations are estimates, are performed independently and will not be indicative of actual results that would occur when multiple variables change concurrently. Calculations are performed prior to the impact of non-financial asset impairment tests.
(3) Non-GAAP financial measure. See the "*Non-GAAP Financial Measures*" advisory section of this MD&A for further information.

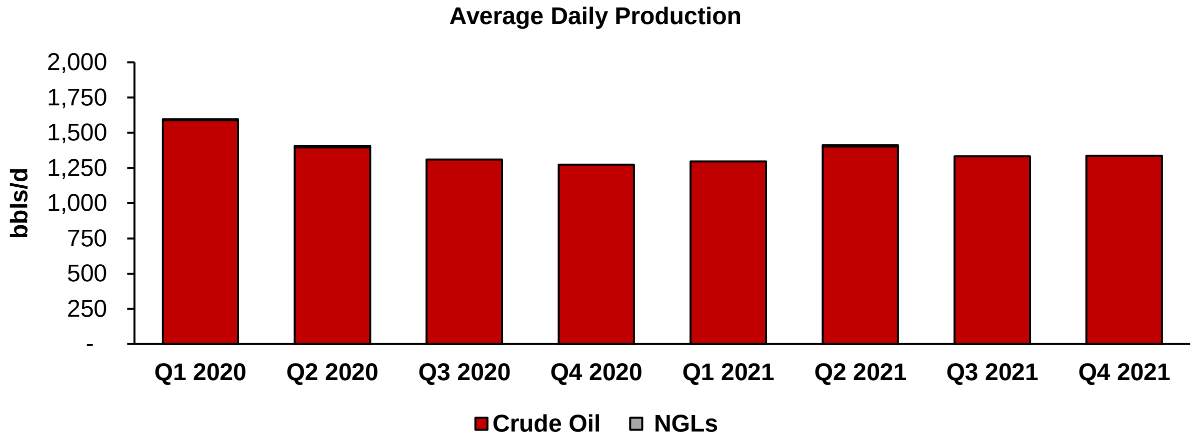
Production volumes

	Three months ended December 31,		% change	**Year ended December 31,**		% change
	2021	2020		**2021**	2020	
Production *(bbls)*						
Crude oil(1)	**122,917**	117,209	5	**489,899**	509,426	(4)
NGLs(2)	**-**	-	-	**842**	1,621	(48)
Total	**122,917**	117,209	5	**490,741**	511,047	(4)
Average daily production *(bbls/d)*						
Crude oil(1)	**1,336**	1,274	5	**1,342**	1,392	(4)
NGLs(2)	**-**	-	-	**2**	4	(50)
Total	**1,336**	1,274	5	**1,344**	1,396	(4)

Notes:
(1) References to crude oil in the above table and elsewhere in this MD&A refer to light, medium and heavy crude oil product types as defined in National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). Our reported crude oil production is a mix of light and medium crude oil and heavy crude oil for which there is not a precise breakdown given our oil sales volumes typically represent blends of more than one type of crude oil.
(2) References to NGLs in the table above and elsewhere in this MD&A refers to condensate.

Touchstone's average production volumes increased 5 percent to 1,336 bbls/d in the fourth quarter of 2021 from 1,274 bbls/d in the prior year equivalent quarter. The nominal increase in production was reflective of our 2021 legacy well optimization program, which arrested year-over-year natural declines. Our fourth quarter three well development drilling program commenced production in January 2022.

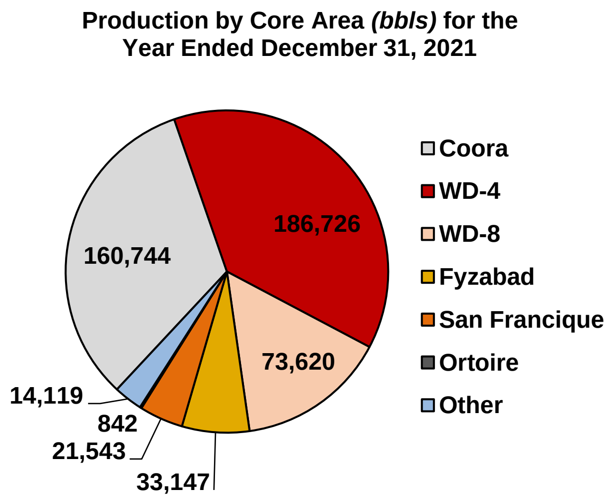
2021 annual crude oil production volumes declined 4 percent compared to the prior year, averaging 1,342 bbls/d. The decrease was reflective of natural declines, given we did not produce additional volumes from new wells since January 2019. In addition, we sold 842 net barrels of NGLs produced from the Cascadura Deep-1 well test in April 2021, while an aggregate 1,621 barrels of NGLs produced from Cascadura-1ST1 well testing operations were sold during the year ended December 31, 2020.

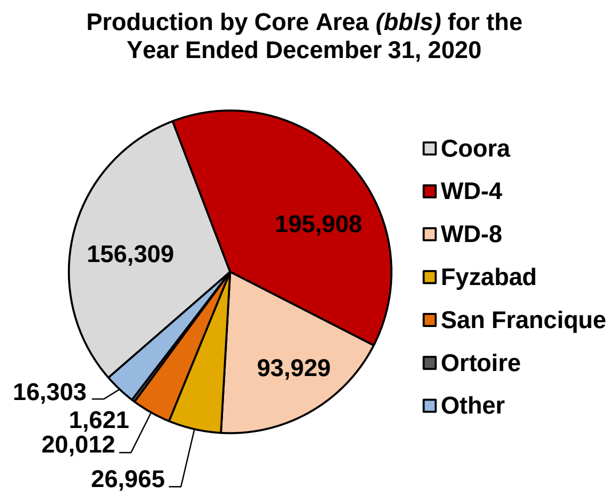


The following table and graphs summarize production by property during the three months and years ended December 31, 2021 and 2020. All properties produced crude oil with the exception of Ortoire, which was comprised of test NGL production in all disclosed periods.

(bbls)	Three months ended December 31, **2021**	Three months ended December 31, 2020	% change	Year ended December 31, **2021**	Year ended December 31, 2020	% change
Coora-1	**37,989**	34,476	10	**147,603**	141,118	5
Coora-2	**2,845**	3,211	(11)	**13,141**	15,191	(13)
WD-4	**49,352**	46,373	6	**186,726**	195,908	(5)
WD-8	**17,060**	19,687	(13)	**73,620**	93,929	(22)
New Dome(1)	**1,565**	1,568	-	**6,268**	7,691	(19)
South Palo Seco(1)	**-**	-	-	**-**	405	(100)
Barrackpore	**1,073**	1,085	(1)	**4,986**	5,000	-
Fyzabad	**6,958**	6,115	14	**33,147**	26,965	23
Palo Seco(1)	**670**	912	(27)	**2,865**	3,207	(11)
San Francique	**5,405**	3,782	43	**21,543**	20,012	8
Ortoire	**-**	-	-	**842**	1,621	(48)
Total production	**122,917**	117,209	5	**490,741**	511,047	(4)

Note:
(1) The assets associated with the properties were classified as held for sale with an effective date of December 31, 2021. Refer to "*Capital Expenditures and Dispositions - PP&E dispositions*" for further information.





Benchmark and realized prices

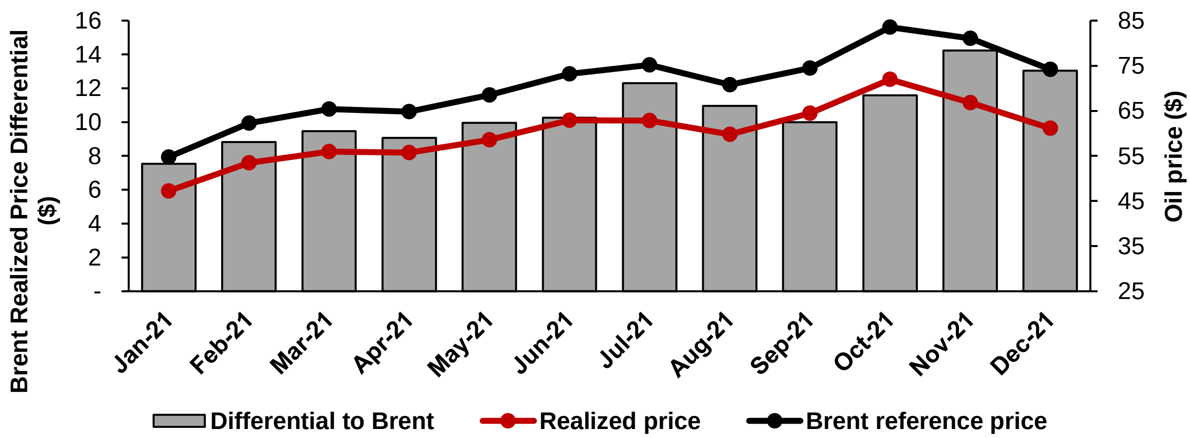
	Three months ended December 31, 2021	2020	% change	Year ended December 31, 2021	2020	% change
Brent average *($/bbl)*	**79.61**	44.32	80	**70.86**	41.96	69
WTI average *($/bbl)*	**77.19**	42.66	81	**67.92**	39.40	72
Average realized price *($/bbl)*[(1)]	**66.81**	37.66	77	**60.25**	38.34	57
Realized price discount as a % of Brent	**(16.1)**	(15.0)		**(15.0)**	(8.6)	
Realized price discount as a % of WTI	**(13.4)**	(11.7)		**(11.3)**	(2.7)	

Note:
(1) Non-GAAP financial measure. See the "*Non-GAAP Financial Measures*" advisory section of this MD&A for further information.

Our crude oil price received is based on quality differentials and international marketing arrangements and therefore are attributed to factors that are beyond our control. Touchstone's crude oil realized price is primarily driven by the Brent benchmark price, as Trinidad crude oil is exported for refining and classified as waterborne crude. The COVID-19 pandemic continued to impact the global economy in 2021, yet crude oil benchmark pricing recovered to levels above pre-pandemic. In 2021, Dated Brent and WTI crude oil benchmarks improved significantly compared to 2020 as demand for crude oil outpaced supply due to increased global crude oil demand amid roll-out efforts of COVID-19 vaccines, a global economic recovery and relaxing of restrictions, despite global participants gradually easing production quotas that began in the second quarter of 2021.

Relative to the fourth quarter of 2020, Touchstone's Brent differential realized during the fourth quarter of 2021 widened from 15.0 percent to 16.1 percent. Similarly, the Brent differential realized during 2021 increased to 15.0 percent from 8.6 percent in 2020. Based on revised pricing arrangements with Heritage in October 2020, we are forecasting a 16 percent discount to Brent throughout 2022 and beyond.

We realized an average price of $66.81 per barrel in the fourth quarter of 2021 compared to an average of $37.66 per barrel in the equivalent quarter of 2020. The 77 percent increase was driven by an 80 percent increase in Brent reference pricing, partially offset by a widening of the realized pricing differential in relation to Brent benchmark pricing. In 2021 Touchstone realized an average crude oil price of $60.25 per barrel, a 57 percent increase relative to $38.34 per barrel received in 2020. The annual increase was attributed to a 69 percent increase in the average Brent reference price, slightly offset by an increase in the realized pricing differential in relation to Brent.



Petroleum sales

($000's)	Three months ended December 31, 2021	2020	% change	Year ended December 31, 2021	2020	% change
Petroleum sales	**8,212**	4,414	86	**29,568**	19,592	51

We sell all produced crude oil volumes to Heritage, with title transferring at our various sales batteries. As at December 31, 2021, we held 7,015 barrels of crude oil inventory in comparison to 4,212 barrels as of December 31, 2020.

Petroleum sales in the fourth quarter of 2021 increased 86 percent to $8,212,000 from $4,414,000 in the fourth quarter of 2020. The increase of $3,798,000 was a result of $3,583,000 from higher realized pricing and $215,000 attributed to higher sales volumes.

2021 petroleum sales were $29,568,000, representing a $9,976,000 or 51 percent increase from the $19,592,000 recognized in 2020. $10,755,000 was attributed to higher realized prices in 2021, partially offset by a $779,000 decrease reflecting reduced 2021 sales volumes.

Other revenue

We recorded $40,000 of other revenue during the year ended December 31, 2021, which was mainly comprised of fees received for selling crude oil on behalf of a third-party operator and proceeds received from workover rig rentals prior to the equipment being leased to a third party (2020 - $121,000). Refer to "*Finance Leases*" for further information.

Royalties

($000's unless otherwise stated)	Three months ended December 31, 2021	2020	% change	Year ended December 31, 2021	2020	% change
Crown royalties	**949**	515		**3,372**	2,272	
Private royalties	**101**	41		**337**	191	
Overriding royalties	**1,673**	672		**5,542**	3,025	
Royalties	**2,723**	1,228	100	**9,251**	5,488	69
On a per barrel basis(1)	**22.15**	10.48	100	**18.85**	10.74	76
As a percentage of petroleum sales(1)	**33.2%**	27.8%	19	**31.3%**	28.0%	12

Note:
(1) Non-GAAP financial measure. See the "*Non-GAAP Financial Measures*" advisory section of this MD&A for further information.

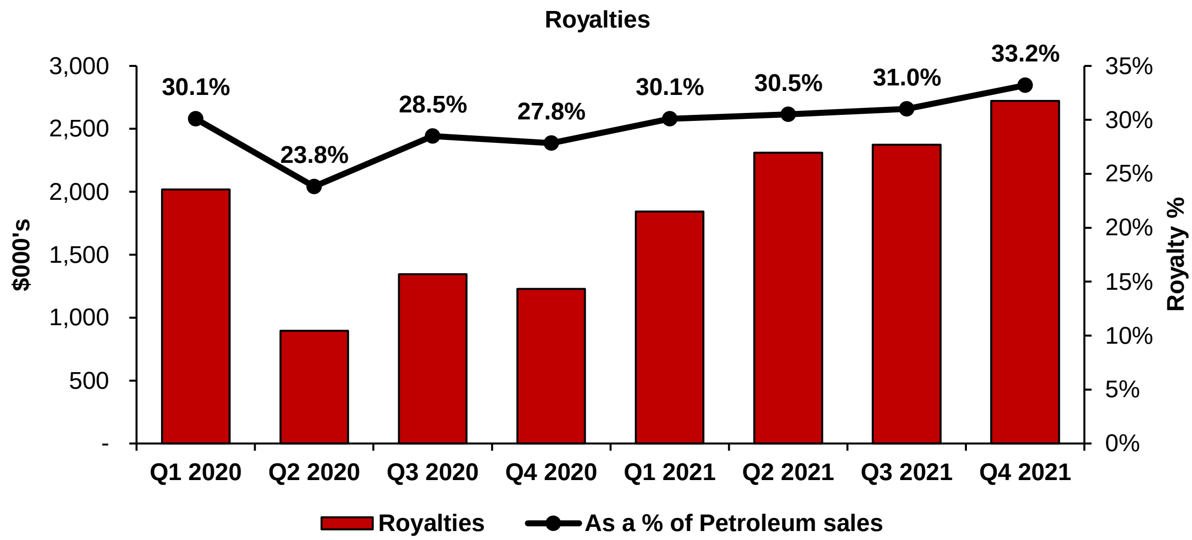
Touchstone is obligated to pay a crown royalty rate of 12.5 percent on all petroleum and natural gas production under MEEI and Heritage licences. For private leases, the Company incurs private royalties between 10 and 12.5 percent of petroleum sales.

In June 2021, we executed ten-year LOAs with Heritage for our Coora, WD-4 and WD-8 blocks which included favourable long-term royalty rate adjustments. In addition to the crown royalty rate of 12.5 percent, the LOAs apply a sliding scale overriding royalty ("ORR") structure, which is indexed to the average price of oil realized in a production month. Base ORR rates are applicable to pre-defined monthly base production levels which decline by 2 percent per annum. For any monthly volumes sold in excess of base production levels, the Company incurs reduced enhanced ORR rates. The former arrangements allowed for new drill ORR incentives, which were reduced ORR rates applicable to production from new wells drilled in the initial two years. This concept was replaced with the super enhanced ORR, which contemplates a further reduction in royalty rates based on increased property production from all field activities. The super enhanced ORR applies a 50 percent reduction from enhanced ORR rates for any production in excess of combined base and enhanced production levels.

The following table summarizes royalty rates attributable to our previous and current LOAs.

Monthly realized oil price ($)	Previous LOA Royalty %		Current LOA Royalty %		
	Base ORR	Enhanced ORR	Base ORR	Enhanced ORR	Super Enhanced ORR
≤ 10.00	10.00	8.00	10.00	6.00	3.00
10.01 - 20.00	13.00	9.00	13.00	6.50	3.25
20.01 - 30.00	15.00	10.00	15.00	7.00	3.50
30.01 - 40.00	20.00	12.00	20.00	7.50	3.75
40.01 - 50.00	25.00	13.00	25.00	8.00	4.00
50.01 - 70.00	33.00	17.50	28.00	15.50	7.75
70.01 - 90.00	33.00	17.50	33.00	17.00	8.50
90.01 - 200.00	35.00	22.50	35.00	20.00	10.00

Royalties as a percentage of petroleum sales were 33.2 percent in the fourth quarter of 2021 compared to 27.8 percent in the prior year equivalent quarter. In 2021, Touchstone's average effective royalty rate was 31.3 percent compared to 28.0 percent in 2020. Relative to both periods of 2020, the change in our 2021 effective royalty rates reflected increases in realized crude oil pricing received in 2021.



Operating expenses

($000's except per bbl amounts)	Three months ended December 31,		% change	Year ended December 31,		% change
	2021	2020		**2021**	2020	
Operating expenses	**1,807**	1,556	16	**7,286**	6,698	9
On a per barrel basis[(1)]	**14.70**	13.28	11	**14.85**	13.11	13

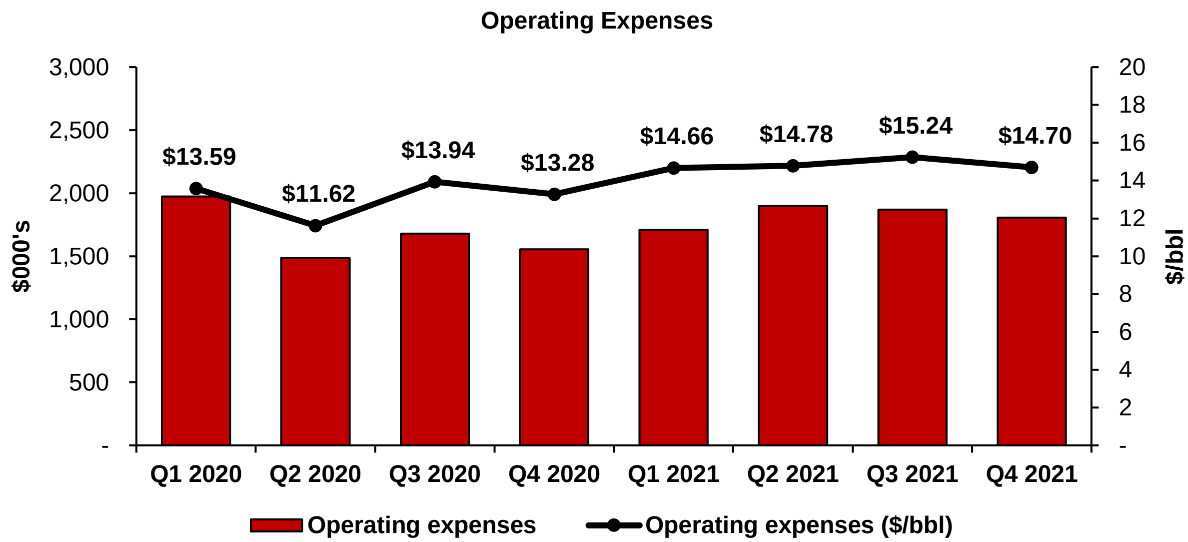
Note:
(1) Non-GAAP financial measure. See the "*Non-GAAP Financial Measures*" advisory section of this MD&A for further information.

Operating expenses include all periodic lease and field-level expenses and include directly attributable employee salaries and benefits.

Fourth quarter and annual 2021 operating expenses increased 16 percent and 9 percent from the corresponding 2020 periods, respectively. 2021 operating expense increases in comparison to 2020 were predominantly from increased field and well servicing costs, as Touchstone initiated legacy oil production optimization efforts in 2021, while discretionary field operating expenses were drastically reduced in March

2020 as a result of the onset of the COVID-19 pandemic. Further, field employees undertook pay reductions in March 2020 which were reinstated in September 2020. The 2021 optimization program was successful, as crude oil production achieved in the fourth quarter of 2021 increased by 5 percent in comparison to fourth quarter 2020 production, mitigating natural declines.

Fourth quarter 2021 operating expenses per barrel increased 11 percent from the fourth quarter of 2020, as Touchstone continued to service legacy wells throughout 2021. Operating expenses on a per barrel basis increased 13 percent to $14.85 in 2021 compared to $13.11 per barrel in 2020, attributable to higher workover and employee costs as the economy recovered and crude oil prices improved in 2021.

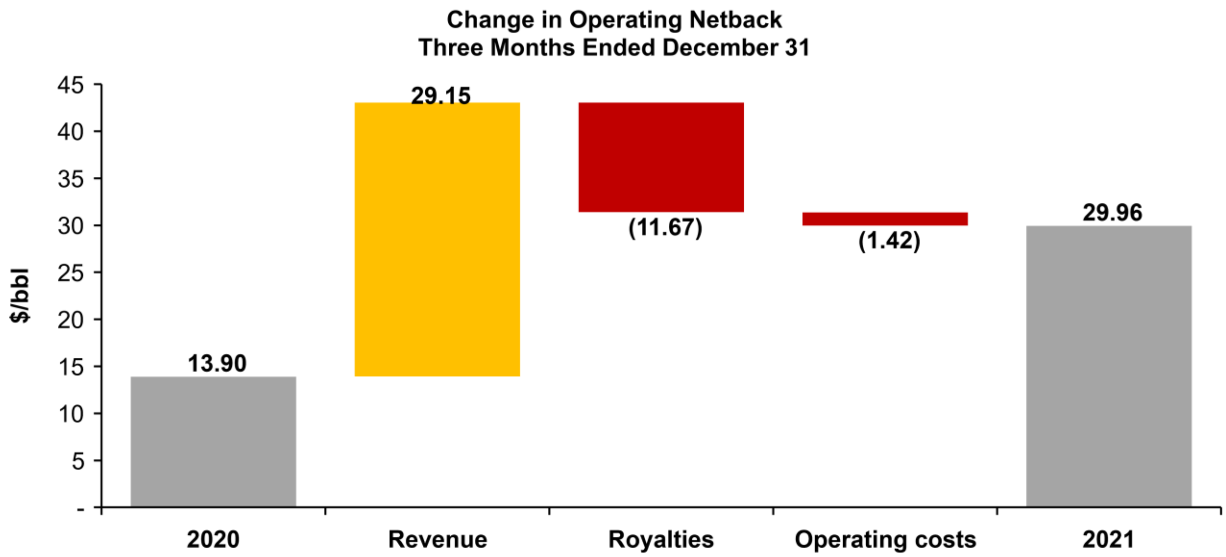


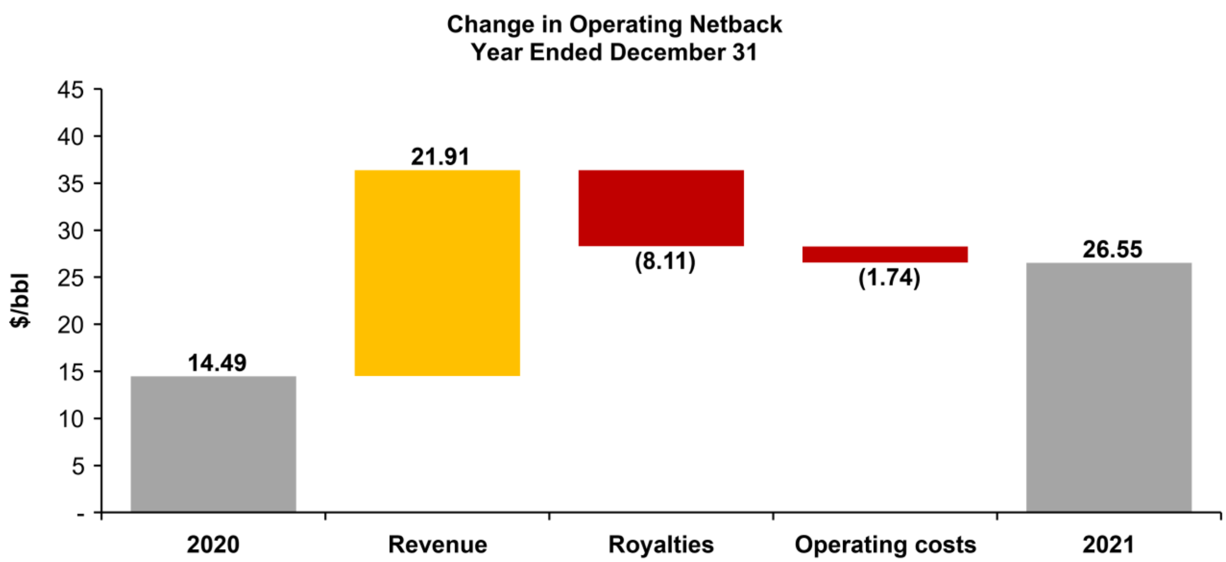
Operating netback

The components of operating netback are set forth below.

	Three months ended December 31, 2021	2020	% change	Year ended December 31, 2021	2020	% change
($000's)						
Petroleum sales[1]	**8,212**	4,414	86	**29,568**	19,592	51
Royalties	**(2,723)**	(1,228)	100	**(9,251)**	(5,488)	69
Operating expenses	**(1,807)**	(1,556)	16	**(7,286)**	(6,698)	9
Operating netback[2]	**3,682**	1,630	100	**13,031**	7,406	76
($/bbl)						
Brent benchmark price	**79.61**	44.32	80	**70.86**	41.96	69
Discount	**(12.80)**	(6.66)		**(10.61)**	(3.62)	
Realized sales price	**66.81**	37.66	77	**60.25**	38.34	57
Royalties	**(22.15)**	(10.48)	100	**(18.85)**	(10.74)	76
Operating expenses	**(14.70)**	(13.28)	11	**(14.85)**	(13.11)	13
Operating netback[2]	**29.96**	13.90	100	**26.55**	14.49	83

Notes:
(1) Excludes other revenue.
(2) Non-GAAP financial measure. See the "*Non-GAAP Financial Measures*" advisory section of this MD&A for further information.





General and administration expenses

($000's except per bbl amounts)	Three months ended December 31,		% change	Year ended December 31,		% change
	2021	2020		**2021**	2020	
Gross G&A expenses	**1,812**	2,623	(31)	**7,485**	6,451	16
Capitalized expenses	**(408)**	(416)	(2)	**(1,184)**	(877)	35
G&A expenses	**1,404**	2,207	(36)	**6,301**	5,574	13
On a per barrel basis[(1)]	**11.42**	18.83	(39)	**12.84**	10.91	18

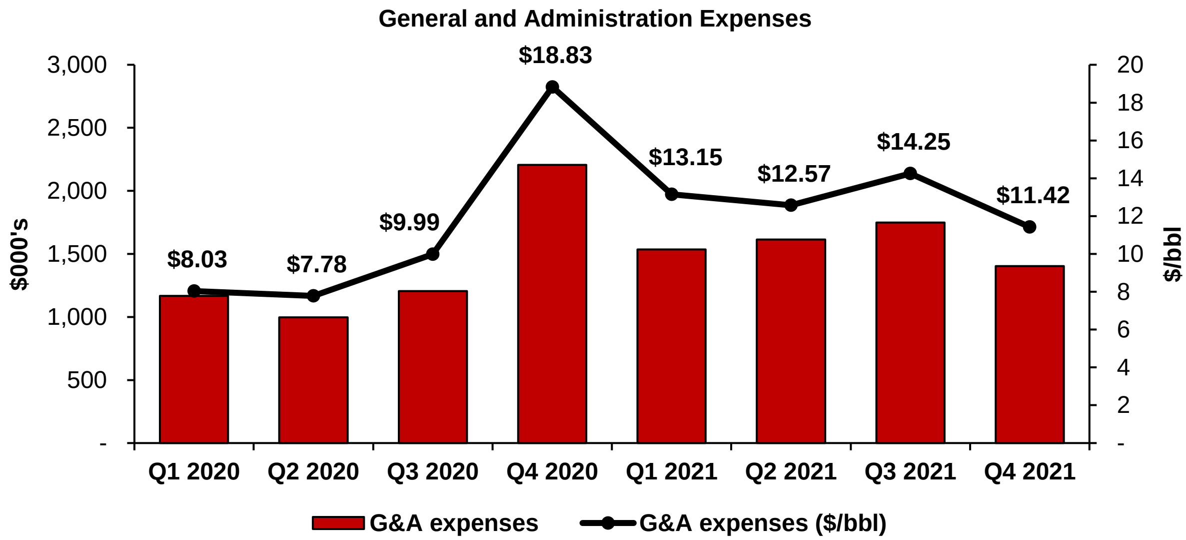
Note:
(1) Non-GAAP financial measure. See the "*Non-GAAP Financial Measures*" advisory section of this MD&A for further information.

Gross G&A expenses in the fourth quarter of 2021 were $1,812,000 compared to $2,623,000 for the equivalent quarter of 2020. Compared to 2020, fourth quarter 2021 G&A expenses decreased primarily from employee incentive plan payments recorded in the prior year period.

The increase in gross G&A expenses in 2021 compared to 2020 was primarily attributed to higher salaries and benefits, as all employees undertook pay reductions in March 2020 which were reinstated in September 2020. Further increases in 2021 public company expenses, insurance and foreign exchange realized from a stronger Canadian dollar relative to the US$ were also reported in comparison to 2020.

The increase in capitalized G&A as a percentage of gross G&A in 2021 in relation to the prior year was predominantly from higher gross G&A costs based on the easing of 2020 cost reductions in 2021 and increased workforce activity allocated to the Ortoire field.

Fourth quarter 2021 G&A expenses were $11.42 per barrel, a 39 percent decrease from the $18.83 per barrel reported in the fourth quarter of 2020 based on lower net G&A costs. 2021 G&A expenses on a per barrel basis increased by 18 percent to $12.84 from $10.91 in the prior year. The increase was attributable to higher net G&A costs and marginally lower production volumes in 2021 compared to 2020.



Net finance expenses

($000's)	Three months ended December 31, 2021	2020	% change	Year ended December 31, 2021	2020	% change
Interest income	**-**	(1)	(100)	**(5)**	(32)	(84)
Lease liability interest expense	**67**	6	100	**81**	21	100
Term loan interest expense	**292**	269	9	**734**	1,151	(36)
Term loan revaluation loss	**279**	-	n/a	**279**	1,158	(76)
Accretion on term loan	**(6)**	(8)	(25)	**45**	232	(81)
Finance expense	**-**	19	(100)	**-**	199	(100)
Production liability revaluation (gain) loss	**(52)**	601	n/a	**83**	759	(89)
Accretion on decom. liabilities	**67**	87	(23)	**273**	297	(8)
Other	**(17)**	(1)	100	**(53)**	(50)	6
Net finance expenses	**630**	972	(35)	**1,437**	3,735	(62)
Cash net finance expenses	**360**	292	23	**823**	1,343	(39)
Non-cash net finance expenses	**270**	680	(60)	**614**	2,392	(74)
Net finance expenses	**630**	972	(35)	**1,437**	3,735	(62)

Net finance expenses in the fourth quarter of 2021 were $630,000 compared to $972,000 for the same period of 2020. During the year ended December 31, 2021, net finance expenses were $1,437,000, representing a 62 percent decrease from the $3,735,000 incurred in the prior year, with 2021 cash finance expenses decreasing by $520,000 from 2020.

Annual 2021 term loan interest expense decreased in comparison to 2020, reflecting a reduced interest rate and lower weighted average outstanding balances from our term credit facility that was refinanced on June 15, 2020. The debt refinancing also reduced 2021 non-cash term loan accretion costs in comparison to 2020. In addition, we incurred $180,000 in finance expenses and recorded a $1,158,000 revaluation loss in connection with the debt refinancing and prepaying our former term loan in 2020. In December 2021, we entered into an amended and restated loan agreement with our lender providing for a $10 million increase in the principal balance to $30 million. In connection with this term loan modification, we recognized a $279,000 non-cash loss on revaluation. Refer to "*Capital Management and Liquidity - Term loan*" for further details.

Production liability revaluation amounts are recognized as a result of a change of production liabilities estimated by the Company at each reporting period. During the three months and year ended December 31, 2021, Touchstone recognized a gain of $52,000 and an aggregate loss of $83,000, respectively, predominately from the strengthening of strip crude oil pricing throughout 2021 (2020 - losses of $601,000 and $759,000). Refer to "*Capital Management and Liquidity - Other liabilities*" for further information.

Foreign exchange and foreign currency translation

Touchstone's presentation currency is the United States dollar. Our parent company has a Canadian dollar functional currency while our Trinidadian subsidiaries have a Trinidad and Tobago dollar functional currency. In each reporting period, the change in values of the C$ and TT$ relative to the US$ reporting currency are recognized. The applicable foreign exchange ("FX") rates used to translate our TT$ and C$ denominated items are set forth below.

FX rates[(1)]	**Three months ended December 31,**		% change	**Year ended December 31,**		% change
	2021	2020		**2021**	2020	
US$:C$ average FX rate	**1.261**	1.303	(3)	**1.254**	1.341	(7)
US$:TT$ average FX rate	**6.789**	6.788	-	**6.787**	6.767	-
	December 31, 2021	September 30, 2021		**December 31, 2021**	December 31, 2020	
US$:C$ closing FX rate	**1.270**	1.271	-	**1.270**	1.274	-
US$:TT$ closing FX rate	**6.792**	6.800	-	**6.792**	6.768	-

Note:
(1) Source: Oanda Corporation average mid daily exchange rates for the specified periods and mid daily exchange rates for the specified dates.

The revenues and expenses of our Canadian head office and Trinidad operations are translated to US$ at the average monthly exchange rates relative to the date of the transactions. Fluctuations in the exchange rate between the TT$ and the US$ and the C$ to US$ could have a material effect on our reported results (refer to "*Market Risk Management - Foreign currency risk*").

During the fourth quarter of 2021, the C$ appreciated 3 percent relative to the US$ in comparison to the corresponding average rates observed in the 2020 fourth quarter. On an annual basis, the C$ appreciated relative to the US$, with 2021 average rates approximately 7 percent stronger than average 2020 foreign exchange rates. Relative to the US$, the TT$ remained range bound during the three months and years ended December 31, 2021 and 2020. In aggregate, Touchstone recorded foreign exchange losses of $37,000 and $185,000 during the three months and year ended December 31, 2021, respectively (2020 - $31,000 gain and $23,000 loss). Foreign exchange losses include amounts that are unrealized in nature and may be reversed in the future as a result of fluctuations in prevailing exchange rates.

The assets and liabilities of our parent company and subsidiaries are translated to US$ dollars at the exchange rate on the reporting period date for presentation purposes, with all foreign currency differences recorded in other comprehensive loss. Relative to the US$, the C$ and TT$ closing rates were consistent on December 31, 2021 versus September 30, 2021 and December 31, 2020. We recognized foreign currency translation gains of $70,000 and $112,000 during the three months and year ended December 31, 2021, respectively (2020 - $1,054,000 and $1,267,000).

Equity-based awards

We have a share option plan pursuant to which options to purchase common shares of the Company may be granted by the Board of Directors ("Board") to our directors, officers, employees and consultants. The exercise price of each share option may not be less than the volume weighted average trading price per common share on the TSX for the five consecutive trading days ending on the last trading day preceding the grant date. Compensation expense is recognized as the options vest. Unless otherwise determined by the Board, vesting typically occurs one third on each of the next three anniversaries of the grant date as recipients render continuous service to the Company, and the share options typically expire five years from the date of the grant.

Share options	**Number of share options**	**Weighted average exercise price (C$)**
Outstanding, January 1, 2020	8,740,600	0.26
Granted	2,892,000	0.64
Exercised	(1,904,666)	0.30
Expired	(147,500)	2.10
Cancelled	(28,000)	0.42
Outstanding, December 31, 2020	**9,552,434**	**0.34**
Granted	**3,013,000**	**1.70**
Exercised	**(1,332,100)**	**0.22**
Outstanding, December 31, 2021	**11,233,334**	**0.72**
Exercisable, December 31, 2021	**5,456,337**	**0.28**

The maximum number of common shares issuable on the exercise of outstanding share options at any time is limited to 10 percent of our issued and outstanding common shares. As of December 31, 2021, we had 11,233,334 share options outstanding, representing 5.3 percent of our outstanding common shares (2020 - 9,552,434 share options representing 4.6 percent of our then outstanding shares). The following table sets forth equity compensation expenses recorded in relation to our equity compensation plan for the periods indicted.

($000's)	**Three months ended December 31,**		% change	**Year ended December 31,**		% change
	2021	2020		**2021**	2020	
Gross equity-based compensation	**394**	111	100	**1,122**	348	100
Capitalized expenses	**(77)**	(19)	100	**(234)**	(46)	100
Equity-based compensation	**317**	92	100	**888**	302	100

For the three months and year ended December 31, 2021, we recorded equity-based compensation of $317,000 and $888,000, respectively. The increases in 2021 equity-based compensation and capitalized equity-based compensation compared to 2020 were primarily attributable to increases in the fair value of equity-based awards granted in 2020 and 2021 based on our higher common share price versus previously granted awards. Further information regarding our equity-compensation plan is included in Note 16 "*Shareholders' Capital*" of our audited financial statements.

Depletion and depreciation expense

($000's except per bbl amounts)	Three months ended December 31, 2021	2020	% change	Year ended December 31, 2021	2020	% change
Depletion expense	**737**	692	7	**2,967**	2,998	(1)
Depreciation expense	**330**	130	100	**448**	506	(11)
Depletion and depreciation expense	**1,067**	822	30	**3,415**	3,504	(3)
Depletion expense on a per barrel basis(1)	**6.00**	5.90	2	**6.06**	5.89	3

Note:
(1) Non-GAAP financial measure. See the "*Non-GAAP Financial Measures*" advisory section of this MD&A for further information.

Our producing petroleum assets included in PP&E are subject to depletion expense. The net carrying value of our producing petroleum assets is depleted using the unit of production method by reference to the ratio of production in the period over the related proved plus probable reserves while also considering the estimated future development costs necessary to bring those reserves into production. Depletion expenses fluctuate based on the amount and type of capital spending, the recognition or reversal of petroleum asset impairments, the quantity of reserves added and production volumes. The depletion rates are calculated on proved plus probable crude oil reserves, considering the future development costs to produce the reserves. As at December 31, 2021, $62,637,000 in future development costs were included in petroleum asset cost bases for depletion calculation purposes (2020 - $59,064,000).

In comparison to the fourth quarter of 2020, fourth quarter 2021 depletion increased 7 percent on an absolute basis and 2 percent on a per barrel basis. The increase in depletion predominately reflected increased carrying values from net petroleum asset PP&E impairment reversals recognized in the fourth quarter of 2020. 2021 annual depletion expenses decreased by 1 percent and increased by 3 percent on a unit of production basis in comparison to 2020. The nominal decline in depletion was predominately a result of lower 2021 production in comparison to 2020.

Assets in the E&E phase are not amortized. Depreciation expense is recorded on corporate assets on a declining balance basis, and right-of-use ("ROU") assets are depreciated over their estimated useful lives on a straight-line basis.

Depreciation expense increased by $200,000 in the fourth quarter of 2021 in comparison to the 2020 equivalent period, reflecting increased carrying values from lease arrangements executed and drilling rig mobilization expenses incurred in the quarter. The decrease in depreciation expense reported in 2021 relative to 2020 was primarily reflective of lower net asset carrying values in the first half of 2021. Further, the Company's oilfield service assets were leased to third parties effective March 1, 2021 and thus were no longer subject to depreciation (refer to "*Finance Leases*").

Impairment of non-financial assets

Entities are required to conduct an impairment test where there is an indication of impairment or reversal of a non-financial asset, and the test may be conducted for a cash-generating unit ("CGU") where an asset does not generate cash inflows that are largely independent of those from other assets. Impairment is recognized when the carrying value of an asset or group of assets exceeds its recoverable amount, defined as the higher of its value in use or fair value less costs of disposal. Any asset impairment that is recorded is recoverable to its original value less any associated depletion and depreciation expense should there be indicators that the recoverable amount of the asset has increased in value since the time of recording the initial impairment. Touchstone assesses E&E asset and PP&E indicators of impairment and impairment reversals on each reporting date.

E&E asset impairment

During the three months and year ended December 31, 2021, we recognized E&E asset impairments of $70,000 and $112,000, respectively (2020 - $744,000 and $795,000). The impairments were related to licence financial obligations for our non-core East Brighton and Cory Moruga exploration properties. The East Brighton licence has expired, and the Company's 16.2 percent non-operated working interest in the Cory Moruga licence continues to have an estimated recoverable value of $nil. The operator of the Cory Moruga licence is currently discussing investment alternatives with the MEEI, which may include licence relinquishment.

As of December 31, 2021, we identified no indicators of impairment relating to our Ortoire CGU, which had a carrying value of $50,760,000 representing the full E&E asset balance on the statement of financial position (2020 - $30,680,000).

PP&E impairment (reversal)

PP&E impairment (reversal) by CGU for the specified periods are disclosed in the following table.

CGU *($000's)*	**Three months ended December 31,**		% change	**Year ended December 31,**		% change
	2021	2020		**2021**	2020	
Coora	**(5,596)**	(2,672)		**(5,596)**	4,268	
WD-4	**(4,060)**	(4,027)		**(4,060)**	1,941	
WD-8	**(4,130)**	(2,009)		**(4,130)**	4,298	
Capital inventory	**-**	116		**-**	116	
PP&E impairment (reversal)	**(13,786)**	(8,592)	60	**(13,786)**	10,623	n/a

We identified indicators of impairment reversal at December 31, 2021 for our Coora, WD-4 and WD-8 CGUs and performed impairment tests to estimate the recoverable amount of each of these CGUs. As a result, we recorded an aggregate impairment reversal of $13,786,000 related to these CGUs for the year ended December 31, 2021. Indicators of impairment reversal were identified as a result of an increase in forecast crude oil prices compared to December 31, 2020, as well as increases in field and drilling activities performed in 2021.

In aggregate, we recorded $10,623,000 in PP&E impairments during the year ended December 31, 2020.

On March 31, 2020, indicators of impairment were present due to the significant decline in crude oil forward pricing predominantly from the effects of COVID-19. Based on the results of impairment tests conducted on all petroleum asset CGUs, an aggregate impairment of $19,215,000 was recognized during the first quarter of 2020 relating to our Coora, WD-4 and WD-8 CGUs.

As of December 31, 2020, indicators of impairment and impairment reversals were noted for all petroleum asset CGUs based upon updated changes in future development plans along with significant crude oil price volatility throughout 2020 amid the continuing economic uncertainty surrounding the impact of COVID-19. We performed impairment tests on all CGUs, resulting in an aggregate impairment reversal of $8,708,000 relating to our Coora, WD-4 and WD-8 CGUs, partially offsetting our first quarter 2020 impairments.

As future commodity prices remain volatile, impairments or impairment reversals could be recorded in future periods. Estimating the recoverable amounts of our E&E and PP&E CGUs involves several assumptions and estimates which are subject to estimation uncertainty, as well as a significant degree of judgement. Changes in any of the key judgements, such as a revision in reserves, changes to forecasted production, changes in forecast crude oil and natural gas prices, inflation rates, operating and future development expenditures, future tax rates and/or after-tax discount rates would impact the estimated recoverable amounts. Further information regarding impairments recorded during the years ended December 31, 2021 and 2020 and their related measurement uncertainty is included in Note 8 "*Impairment*" of our audited financial statements.

Decommissioning liabilities and abandonment fund

Our decommissioning and reclamation liabilities relate to future site restoration and well abandonment costs including the costs of production equipment removal and land reclamation based on current Trinidad environmental regulations. The estimates are reviewed at least quarterly and adjusted as new information regarding the liability is determined.

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

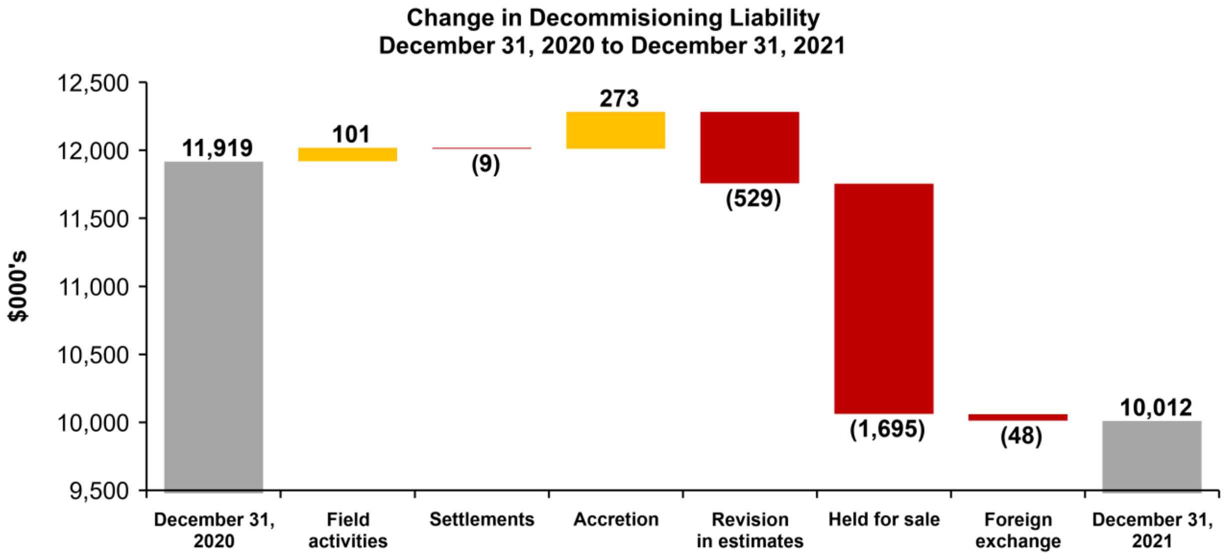
With respect to decommissioning liabilities associated with our LOAs with Heritage, we are obligated for our proportional cost of all abandonments defined as our percentage of crude oil sold in a well in comparison to the well's cumulative historical production. Touchstone is not responsible for the decommissioning of existing infrastructure and sales facilities. We are required to remit $0.25 per barrel sold to Heritage into a joint well abandonment fund. These funds are used solely for well decommissioning. Any costs of wells that are abandoned during the relevant licence term are credited against any future contributions of the well abandonment fund. Upon expiration of the relevant agreement, Heritage shall calculate our total abandonment liability. If our liability exceeds the well abandonment fund, we are obligated to pay the difference. Conversely, if the proceeds of the fund exceed the liability, the surplus shall be returned to Touchstone. These amounts are also recognized as long-term abandonment fund assets on the consolidated statements of financial position.

As of December 31, 2021, we reported $1,278,000 of accrued or paid contributions into MEEI and Heritage abandonment funds as long-term abandonment fund assets (2020 - $1,226,000). $54,000 of the abandonment fund asset balance was classified as assets held for sale as at December 31, 2021 (refer to "*Capital Expenditures and Dispositions - PP&E dispositions*" for further information).

Pursuant to our Heritage operating agreements, we fund Heritage's $0.25 per barrel obligation with respect to Heritage's head licence commitments with the MEEI. As the Company cannot access the contributions for our future well abandonments, the payments are included in operating expenses as incurred. Additionally, we are further obligated to remit $0.03 per barrel to Heritage into a general abandonment fund. The non-refundable proceeds are used as a contingency fund for the decommissioning and removal of infrastructure and facilities within a field and are expensed to operating expenses as incurred.

Touchstone is responsible for all site restoration, well abandonment costs and removal of infrastructure and facilities used in petroleum operations conducted on our private production and exploration agreements.

We estimated the net present value of the cash flows required to settle our decommissioning liabilities to be $10,012,000 as at December 31, 2021 (2020 - $11,919,000). The estimate included assumptions in respect of actual costs to abandon wells or reclaim a property, the time frame in which such costs will be incurred, historical well production and annual inflation factors. December 31, 2021 decommissioning liabilities were estimated using a weighted average long-term risk-free rate of 5.3 percent and a long-term inflation rate of 1.6 percent (2020 - 4.9 percent and 1.8 percent). $67,000 and $273,000 of accretion expenses were recognized during the three months and year ended December 31, 2021 to reflect the increase in decommissioning liabilities associated with the passage of time, respectively (2020 - $87,000 and $297,000). $1,695,000 of the decommissioning liability was reported as liabilities associated with assets held for sale as at December 31, 2021 (refer to "*Capital Expenditures and Dispositions - PP&E dispositions*" for further information).



Decommissioning liability details as of December 31, 2021, excluding those classified as held for sale, are summarized in the table below.

Number of well locations (net)	Number of facility locations (net)	Undiscounted balance *($000's)*	Inflation adjusted balance *($000's)*	Discounted balance *($000's)*
735.6	3.0	13,725	15,943	10,012

Environmental stewardship is a core value at Touchstone, and abandonment and reclamation activities are made in a prudent, responsible manner with the oversight of the Board and in accordance with local regulations. Decommissioning liabilities are considered critical accounting estimates. There are significant uncertainties related to future decommissioning expenditures, and the impact on our consolidated financial statements could be material. The eventual timing of and costs for these expenditures could differ from current estimates. Further information regarding decommissioning liabilities is included in Note 14 "*Decommissioning Liabilities and Abandonment Fund*" of our audited financial statements.

Income taxes

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

- Supplemental Petroleum Tax ("SPT") — 18 percent of gross liquids revenue less related royalties
- Petroleum Profits Tax ("PPT") — 50 percent of net taxable profits
- Unemployment Levy ("UL") — 5 percent of net taxable profits
- Green Fund Levy ("GFL") — 0.3 percent of gross revenue

SPT is computed and remitted on a quarterly basis and is applicable to produced petroleum liquids. Actual rates vary based on the average realized selling prices of petroleum liquids in the applicable quarter. The SPT rate is nil when the weighted average realized price of petroleum liquids for a given quarter is below $50.00 per barrel and 18 percent when weighted average realized prices fall between $50.00 and $90.00. For quarterly average petroleum prices greater than $90.00, the SPT rate is 18 percent plus 0.2 percent per $1.00 above $90.00. For the 2021 and 2022 financial years, the threshold for SPT increased from $50.00 to $75.00. The revenue base for the calculation of SPT is petroleum sales from liquids products less related royalties paid, less 25 percent investment tax credits on mature oilfields for allowable tangible and intangible capital expenditures incurred in the applicable fiscal quarter. Our Ortoire property is not considered a mature oilfield, and thus no capital spending investment tax credits are applicable.

Annual PPT and UL taxes are calculated based on net taxable profits. Net taxable profits are determined by calculating gross revenue less: royalty expenses, SPT paid during the year, capital allowances, operating expenses, G&A expenses, and certain finance expenses. PPT losses may be carried forward indefinitely to reduce PPT in future years but can only be used to shelter a maximum of 75 percent of income subject to PPT per annum. UL losses cannot be carried forward to reduce future year UL. Developmental and exploratory capital expenditure allowances (tangible and intangible) are amortized on a five-year straight-line basis.

Our Trinidad oilfield service subsidiary, which primarily leases oilfield service equipment to third-party contractors for use in our exploration and production subsidiaries, is subject to the greater of a 30 percent corporation income tax calculated on net taxable profits or a 0.6 percent business levy calculated on gross revenue. The service company is also subject to the GFL noted above. All corporate income tax losses can be carried forward indefinitely, and allowances vary from 10 percent to 33.3 percent for various capital expenditures incurred in the year.

The following table sets forth current income tax expense (recovery) for the three months and years ended December 31, 2021 and 2020.

($000's)	**Three months ended December 31,**		% change	**Year ended December 31,**		% change
	2021	2020		**2021**	2020	
SPT	**-**	-		**-**	5	
PPT	**124**	(55)		**883**	142	
UL	**51**	(23)		**354**	49	
Business levy	**4**	1		**20**	12	
GFL	**29**	12		**101**	66	
Current income tax expense (recovery)	**208**	(65)	n/a	**1,358**	274	100

During the three months and year ended December 31, 2021, we recognized $208,000 and $1,358,000 of current income tax expenses, respectively, compared to a recovery of $65,000 and a $274,000 expense recognized in the corresponding 2020 periods. The increase in 2021 current income taxes relative to 2020 was primarily attributed to accrued PPT and UL expenses based on increased annual operating entity estimated taxable profits.

Touchstone's $14,450,000 net deferred income tax liability balance represented the estimated future tax consequences attributable to differences between financial statement carrying amounts of assets and liabilities and their respective tax bases as at December 31, 2021 (2020 - $7,021,000). The deferred income tax balance remained in a liability position mainly from the discrepancy between the carrying values and the tax values of the Company's petroleum assets included in PP&E.

During the three months and year ended December 31, 2021, we recognized deferred income tax expenses of $7,226,000 and $7,463,000, respectively (2020 - expense of $3,856,000 and recovery of $6,273,000). The deferred income tax expense in the three months and year ended December 31, 2021 periods were primarily reflective of PP&E impairment reversals recognized in the fourth quarter, which increased financial statement carrying values and increased the corresponding deferred income tax liability balance. The deferred income tax recovery reported during the year ended December 31, 2020 was primarily due to net PP&E impairments recognized in the year.

Tax regulations and legislation and interpretations thereof in the various jurisdictions in which we operate are continually changing. As a result, there are generally a number of tax matters under review, and we believe that the provision for income taxes is adequate. Further information regarding our current and deferred income taxes is included in Note 15 "*Income Taxes*" of our audited financial statements.

Capital Expenditures and Dispositions

E&E asset expenditures

E&E asset expenditures include asset additions in areas that have been determined to be in the exploration phase. Touchstone's core exploration property is the Ortoire exploration block. The Company's E&E asset expenditures during the respective periods are summarized in the following table.

($000's)	Three months ended December 31, 2021	2020	% change	Year ended December 31, 2021	2020	% change
Licence financial obligations	**281**	787		**1,056**	962	
Geological and seismic	**-**	438		**2,438**	512	
Drilling, completions and well testing	**2,063**	6,877		**14,295**	14,282	
Equipment and facilities	**99**	220		**799**	1,155	
Capitalized G&A	**280**	437		**835**	631	
Other	**223**	272		**683**	319	
Total expenditures	**2,946**	9,031	(67)	**20,106**	17,861	13

Fourth quarter and annual 2021 Ortoire E&E asset expenditures were $2,946,000 and $20,106,000, respectively. Touchstone's 2021 capital program remained heavily focused on exploration activities on the Ortoire property, where we predominately conducted production testing operations on the Chinook-1 and Cascadura Deep-1 wells drilled in the second half of 2020, completed the Royston area 22-kilometre seismic program, and drilled and initiated production testing of the Royston-1 exploration well. Further investments were also directed toward the Coho and Cascadura surface facilities (refer to "*Ortoire Operations*" for further details).

During the comparative periods of 2020, we focused E&E investments on drilling the Chinook-1 and Cascadura Deep-1 well, two Cascadura-1ST1 well production tests, and initial expenditures relating to the Coho-1 well surface facility and tie-in.

PP&E expenditures

($000's)	Three months ended December 31, 2021	2020	% change	Year ended December 31, 2021	2020	% change
Drilling and completions	**4,264**	207		**5,108**	374	
Rig mobilization	**401**	-		**1,850**	-	
Capitalized G&A	**128**	(21)		**349**	246	
Corporate / other	**397**	-		**450**	89	
Total expenditures	**5,190**	186	100	**7,757**	709	100

For the three months and year ended December 31, 2021, PP&E expenditures were $5,190,000 and $7,757,000, respectively. In the fourth quarter of 2021, we resumed infill drilling operations on our legacy assets, drilling three (gross and net) wells. The wells were completed and on production in the first quarter of 2022. In addition, an aggregate of $1,850,000 was incurred in 2021 for costs to mobilize a third-party drilling rig to Trinidad. 2021 corporate asset expenditures included investments related to the new Rio Claro office in Trinidad and information technology upgrades.

We conducted minimal field development activity throughout the 2020 financial year, as well recompletions were limited based on declines in crude oil pricing.

PP&E dispositions

In 2021 the Company executed sale and purchase agreements with a third party to dispose of our New Dome, Palo Seco and South Palo Seco properties for aggregate consideration of $350,000, subject to customary closing adjustments. The transactions were effective December 31, 2021 and remain subject to standard regulatory approvals. We consider the properties to be non-core due to the associated decommissioning obligations, operating expenses that were substantially higher than our corporate average and limited scalability. The properties generated nominal operating netbacks and contributed an average of 25 bbls/d of crude oil sales during the year ended December 31, 2021 (2020 - 31 bbls/d).

Immediately prior to classifying the assets and associated liabilities as held for sale, we conducted a review of the assets' recoverable amounts based on the expected consideration to be received and transferred these assets at their carrying amount, with no impairment recognized. The following table specifies the carrying values that were classified as held for sale on our December 31, 2021 consolidated statement of financial position.

($000's)	**December 31, 2021**
PP&E	**1,122**
Abandonment fund	**54**
Assets held for sale	**1,176**
Decommissioning obligations	**(1,695)**
Liabilities associated with assets held for sale	**(1,695)**
Net liabilities held for sale	**(519)**

Finance Leases

Effective March 1, 2021, we entered into separate three-year arrangements to lease our oilfield service rigs and swabbing units to two third-party contractors for aggregate proceeds of approximately $1,120,000. Principal payments commenced in March 2021, and we continue to hold title to the assets until all principal payments have been collected. The lease arrangements were classified as finance leases, as substantially all of the risks and rewards incidental to ownership of the underlying assets are held by the lessees. On March 1, 2021, the $856,000 carrying value of the leased assets were reclassified from PP&E to other assets on the consolidated statement of financial position, with a loss of $4,000 recorded. As of December 31, 2021, our aggregate finance lease receivable balance was $738,000, of which $647,000 was included in long-term other assets on the consolidated statement of financial position.

Capital Management and Liquidity

Capital management

Our policy is to maintain a strong capital base to preserve investor, creditor, and market confidence and to sustain the future development of our business. We consider our capital structure to include shareholders' equity, working capital and long-term bank debt. Touchstone's capital management objective is to fund current period decommissioning and capital expenditures necessary for the replacement of production declines using only funds flow from operations. Exploration activities and profitable growth activities will be financed with a combination of funds flow from operations and other sources of capital. We use share equity and term debt as our primary sources of capital.

As at December 31, 2021, Touchstone had a cash balance of $17,936,000, a working capital surplus of $6,925,000 and $30,000,000 drawn on our term credit facility. In December 2021, we expanded the principal balance of our term loan from $20 million to $30 million and withdrew the remaining available balance of $15 million on December 30, 2021. The credit facility does not require the commencement of principal payments until September 2022, and financial covenants are not tested until the year ended December 31, 2022.

Our near-term development plan is strategically balanced between increasing base crude oil production levels, bringing Ortoire natural gas discoveries onstream and proceeding with our Ortoire exploratory activities. We will continue to take a measured approach to future developmental and exploration drilling in an effort to manage financial liquidity while proceeding with this plan.

When evaluating our capital structure, Management's long-term strategy is to maintain net debt to trailing twelve-month funds flow from operations at or below a ratio of two times in a normalized commodity price environment. This ratio may increase at certain times as a result of increased capital expenditures or low commodity prices. We also monitor our capital management through the net debt to total managed capital ratio. Our strategy is to utilize more equity than debt, thereby targeting net debt to total managed capital at a ratio of less than 0.4 to 1. The following table details our internal capital management calculations for the years ended December 31, 2021 and 2020.

($000's)	**Target measure**	**December 31, 2021**	December 31, 2020
Current assets		**(27,856)**	(29,312)
Current liabilities		**20,931**	16,379
Working capital surplus[1]		**(6,925)**	(12,933)
Principal long-term balance of term loan		**27,000**	7,500
Net debt (surplus)[1]		**20,075**	(5,433)
Shareholders' equity		**67,558**	60,365
Total managed capital[1]		**87,633**	54,932
Annual funds flow from operations		**4,107**	263
Net debt to funds flow from operations ratio[1]	**at or < 2.0 times**	**4.89**	n/a
Net debt to total managed capital ratio[1]	**< 0.4 times**	**0.23**	n/a

Note:
(1) Non-GAAP financial measure. See the "*Non-GAAP Financial Measures*" advisory section of this MD&A for further information.

Shareholders' equity

The Company is authorized to issue an unlimited number of voting common shares without nominal or par value. From time to time, we may access capital markets to meet our additional financing needs and to maintain flexibility in funding our capital programs. The following table summarizes Touchstone's outstanding common shares and share options as at the date of this MD&A, December 31, 2021 and December 31, 2020.

	March 25, 2022	**December 31, 2021**	December 31, 2020
Common shares outstanding	**210,826,727**	**210,731,727**	209,399,627
Share options outstanding	**10,876,534**	**11,233,334**	9,552,434
Fully diluted common shares	**221,703,261**	**221,965,061**	218,952,061

Further information regarding our shareholders' capital and equity-based compensation plan is included in "*Results of Operations - Equity-based awards*" herein and in Note 16 "*Shareholders' Capital*" of the audited financial statements.

Term loan

Touchstone Exploration (Trinidad) Ltd., the Company's indirectly wholly owned Trinidadian subsidiary, entered into a $20 million, seven-year term credit facility arrangement effective June 15, 2020 with Republic Bank Limited, a chartered bank owned by Republic Financial Holdings Limited. Republic Financial Holdings Limited is headquartered in Trinidad and the registered owner of twelve banks in the Caribbean region, as well as other financial services subsidiaries. The term credit facility arrangement is a senior secured syndicated loan, with Republic Bank Limited acting as initial lender, arranger and administrative agent.

On closing, we withdrew $15 million to satisfy our obligations relating to prepaying our former C$20 million Canadian-based term loan (the "Retired Term Loan"). On November 27, 2020, the parties executed a term loan amending agreement, allowing the Company to repay $7.5 million of the $15 million term loan balance on December 15, 2020. On October 1, 2021, we withdrew an additional $7.5 million, resulting in a principal balance of $15 million outstanding.

On December 21, 2021, the parties entered into an amended and restated loan agreement providing for a $10 million increase in the principal balance to $30 million. The amendment did not amend any other terms of the prior term loan agreement. Effective December 30, 2021, we withdrew an additional $15 million on the credit facility, resulting in the full principal balance of $30 million outstanding.

The term loan agreement bears a fixed interest rate of 7.85 percent per annum, compounded and payable quarterly. Twenty equal and consecutive quarterly principal payments of $1.5 million commence on September 15, 2022. Prepayments are currently permitted with a one percent penalty and a 30-day notice period, and no penalty shall apply on principal repayments after three years. The term loan agreement is principally secured by a pledge of equity interests and fixed and floating security interests over all present and after acquired assets of Touchstone Exploration (Trinidad) Ltd. and its wholly-owned Trinidadian subsidiary, POGL. The agreement contains industry standard representations and warranties, undertakings, events of default, and financial covenants, which will be tested on an annual basis commencing with the year ended December 31, 2022.

For financial reporting purposes, the term loan is initially measured at fair value and subsequently measured at amortised cost, with the aggregate associated financing fees unwound using the effective interest rate method to the face value at maturity. As of December 31, 2021 the term loan balance was $29,896,000, with $26,896,000 classified as long-term and $3,000,000 classified as current on the consolidated statement of financial position.

At all times, we must maintain a cash reserves balance of not less than the equivalent of two subsequent quarterly interest payments. Touchstone classified $1,178,000 of cash as long-term restricted as at December 31, 2021 (2020 - $294,000).

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

Other liabilities

Lease liabilities

The Company is a party to lease arrangements for a drilling rig, office space and office equipment. As of December 31, 2021, we recognized $2,648,000 in aggregate lease liabilities on our consolidated statement of financial position, of which $2,265,000 was classified as long-term (2020 - $383,000 and $335,000, respectively).

In March 2021, we entered into a minimum three-year drilling services contract with a third party to supply a North American based drilling rig to Trinidad in 2021. Pursuant to the arrangement, we are required to utilize the rig for a minimum of 120 days per annum over the initial three-year term. The drilling rig commenced operations in October 2021, with the Company recognizing a $2,479,000 lease liability and associated ROU asset. Further information regarding our lease obligations is included in Note 11 "*Lease Liabilities* " of the audited financial statements.

Production liability

In connection with the Retired Term Loan, we granted our former lender a production payment equal to 1.33 percent of crude oil and natural gas sales from Trinidad land holdings, payable quarterly through October 31, 2023. Upon repayment of the Retired Term Loan, the parties entered into an amended production payment agreement to continue the obligation under its previous terms and conditions.

The production liability is revalued at each reporting period based on changes to internally forecasted crude oil and natural gas production and forward crude oil and natural gas pricing and is thus subject to variability in each reporting period. During the three months and year ended December 31, 2021, we recognized a gain of $52,000 and an aggregate loss of $83,000, respectively, predominately from the strengthening of strip crude oil pricing throughout 2021 (2020 - losses of $601,000 and $759,000). At December 31, 2021, the Company's estimated production liability balance was $1,211,000, of which $908,000 was classified as long-term and included in other liabilities on the consolidated statement of financial position (2020 - $1,519,000 and $1,357,000, respectively).

Liquidity risk

Liquidity risk is the risk that we will not be able to meet our obligations associated with our financial liabilities. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. We believe that future cash flows will be adequate to meet financial obligations as they come due.

Our 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 our business objectives. Stewardship of our capital structure and potential liquidity risk is managed through our financial and operating forecast process. The forecast of our future cash flows is based on estimates of crude oil and natural gas production, crude oil forward prices, capital expenditures, royalty expenses, operating expenses, G&A expenses, income tax expenses and other investing and financing activities. The forecast is regularly updated based on changes in commodity prices, capital expenditures, production expectations and other factors that in our view would impact cash flow.

To manage our capital structure, we may reduce our fixed cost structure, adjust capital and exploration spending, issue new equity or seek additional sources of debt financing. We will continue to manage our capital expenditures to reflect current financial resources in the interest of sustaining long-term viability. The following table sets forth estimated undiscounted cash outflows and financial maturities of our financial liabilities as at December 31, 2021.

($000's)	**Recognized in financial statements**	**Undiscounted cash outflows**	**Financial maturity by period**		
			Less than 1 year	**1 to 3 years**	**Thereafter**
Accounts payable and accrued liabilities	Yes – liability	**16,000**	16,000	-	-
Income taxes payable	Yes – liability	**236**	236	-	-
Lease liabilities	Yes – liability	**3,224**	616	2,168	440
Term loan principal	Yes – liability	**30,000**	3,000	12,000	15,000
Term loan interest	No – recognized as incurred	**7,261**	2,316	3,375	1,570
Estimated production liability	Yes – liability	**1,880**	429	1,451	-
Total financial liabilities		**58,601**	**22,597**	**18,994**	**17,010**

We actively monitor our liquidity to ensure that cash flows, potential credit facility capacity and working capital are adequate to support these financial liabilities, as well as the Company's capital programs.

Contractual Obligations and Commitments

We have minimum work obligations under various operating agreements with Heritage, exploration commitments under our Cory Moruga and Ortoire block exploration and production licences with the MEEI, and various lease commitments for office space and motor vehicles. The following table outlines our estimated minimum contractual payments as at December 31, 2021.

($000's)		Estimated payments due by year			
	Total	**2022**	**2023**	**2024**	**Thereafter**
Operating agreement commitments					
Coora blocks	**14,323**	5,356	88	2,743	6,136
WD-4 block	**4,808**	39	41	1,406	3,322
WD-8 block	**4,845**	71	73	1,403	3,298
Fyzabad block	**835**	28	76	78	653
Cory Moruga exploration block	**1,293**	94	99	105	995
Ortoire exploration block	**4,426**	313	647	686	2,780
Office and equipment leases	**874**	432	102	102	238
Minimum payments	**31,404**	**6,333**	**1,126**	**6,523**	**17,422**

Under the terms of our Heritage operating agreements, we are required to fulfill minimum work obligations on an annual basis over the specific licence term. With respect to these obligations, as at December 31, 2021, we had four development wells and five heavy workover commitments to perform in 2022.

As of December 31, 2021, we completed all of our minimum work commitment obligations pursuant to our Ortoire Licence. Subsequent to year end, we were notified that the Trinidad government approved an extension to the exploration period of our Ortoire Licence to July 31, 2026. Upon execution, we will be required to drill three exploration wells prior to the end of the amended term which are excluded from the table above.

Market Risk Management

We are exposed to normal financial risks inherent in the international oil and natural gas industry including, but not limited to, commodity price risk, foreign exchange rate risk, credit risk and liquidity risk. The risk exposures are proactively reviewed, and Management seeks to mitigate these risks through various business processes and internal controls.

Management has overall responsibility for the establishment of risk management strategies and objectives. Our risk management policies are designed to identify the risks faced by the Company, to set appropriate risk limits, and to monitor adherence to risk limits. Risk management policies are reviewed and revised regularly to reflect changes in market conditions and our operating activities. Management of cash flow variability is an integral component of our business strategy. Changing business conditions are monitored regularly and, where material, reviewed with the Board to establish risk management guidelines to be used by Management.

Commodity price risk

The Company is exposed to commodity price movements as part of our operations. Crude oil prices are impacted by the world and continental/regional economy and other events that dictate the levels of supply and demand. Further, our realized crude oil price is based on quality differentials and international marketing arrangements and therefore are attributed to factors that are beyond our control. Consequently, any changes in crude oil pricing could affect our cash flow from operations, the value of our properties, the level of capital expenditures and our ability to meet financial obligations as they come due.

In addition, we entered into a long-term fixed price natural gas sales agreement in 2020 with NGC, which contains options for price negotiations on each fifth anniversary of the initial production date. The price of natural gas in Trinidad is predominantly based on domestic supply and demand, with demand largely from domestic power generation and petrochemical facilities. There can be no guarantee that we may be able to negotiate future price increases for natural gas, and a material decline in future natural gas sales prices will result in a reduction of the Company's cash flow from operations and financial position.

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

We had no commodity financial contracts in place as of the date hereof or during the years ended December 31, 2021 and 2020. For the year ended December 31, 2021, with all other variables held constant, a 10 percent increase or decrease in the realized pricing received from crude oil would have resulted in an approximate $1,050,000 increase or decrease in comprehensive income (2020 - $319,000 increase or $592,000 decrease).

We will continue to monitor forward commodity prices and may enter future commodity-based risk management contracts to reduce the volatility of petroleum sales and protect future development and exploration capital programs. Additionally, we continually review our capital program and implement initiatives to adapt to such price changes.

Foreign currency risk

Foreign currency exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of our financial assets or liabilities. As we primarily operate in Trinidad, fluctuations in the exchange rate between the TT$ and the US$ could have a significant effect on financial results. Although the sales prices of crude oil are determined by reference to US$ denominated benchmark prices, the majority of the invoices for such sales are paid in TT$, exposing the Company to foreign exchange risk. To mitigate this risk, we attempt to match revenues received in TT$ by entering into contracts denominated and payable in TT$ when possible. We also attempt to limit our exposure to foreign currency risk through collecting and paying foreign currency denominated balances in a timely fashion. In addition, we have US$ denominated debt and related interest payments. These risks are currently mitigated by the fact that the TT$ is informally pegged to the US$.

Touchstone has further foreign exchange exposure on cash balances denominated in Canadian dollars and pounds sterling, on head office costs and a production liability denominated in Canadian dollars, and costs denominated and payable in pounds sterling required to maintain our AIM listing. Any material movements in the C$ to US$ and the pounds sterling to US$ exchange rates may also have a material effect on our reporting results (refer to "*Results of Operations - Foreign exchange and foreign currency translation*").

Touchstone has no contracts in place to manage foreign currency risk as at the date hereof or during the years ended December 31, 2021 and 2020. For the year ended December 31, 2021, with all other variables held constant, a 5 percent change in the C$ to US$ and TT$ to US$ exchange rates would have resulted in an approximate $108,000 increase or decrease in comprehensive income (2020 - $811,000).

Credit risk

Credit risk is the risk of a counterparty failing to meet its obligations in accordance with the agreed upon terms. We may be exposed to third-party credit risk through our contractual arrangements with current or future joint operation partners, marketers of our 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 derivative transactions. However, we are exposed to sole purchaser risk in Trinidad as Heritage is the sole purchaser of crude oil and NGC is the sole purchaser of future natural gas production.

In addition, the Company historically has aged accounts receivables owing for Trinidad-based value added taxes ("VAT"). In comparison to December 31, 2020, our past due accounts receivable balance increased by $2,461,000 as a result of increased overdue VAT balances based on elevated capital and operational spending in 2021. Although ultimate collection is erratic and therefore the timing thereof cannot be estimated with any certainty, Management believes that all of the balances are ultimately collectable as we have not experienced any past collection issues. The aging of our accounts receivable is disclosed in the following table.

($000's)	**December 31, 2021**	December 31, 2020
Not past due	**3,181**	2,781
Past due (greater than 90 days)	**4,365**	1,904
Accounts receivable	**7,546**	4,685

We have further credit risk associated with our long-term finance lease receivable balances. We have determined that the associated credit risk is negligible, as the assets are secured by the underlying equipment, with ownership transferring to the counterparties subsequent to receipt of the final lease payments (refer to "*Finance Leases*").

Further details relating to our financial assets and credit risk can be found in Note 5 "*Financial Assets and Credit Risk*" of the audited financial statements.

Off-balance Sheet Arrangements

The Company does not believe it has any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a material current or future effect on the Company's financial condition, results of operations, liquidity or capital expenditures, other than the commitments noted in "*Contractual Obligations and Commitments*" herein.

Related Party Transactions

Touchstone's Corporate Secretary and a director is a senior partner of our Canadian legal counsel, Norton Rose Fulbright Canada LLP. For the three months and year ended December 31, 2021, $34,000 and $81,000 in legal fees and disbursements charged by Norton Rose Fulbright Canada LLP were incurred, respectively (2020 - $110,000 and $214,000). These amounts have been recorded at the amounts that were agreed upon by the two parties. $24,000 was included in accounts payable and accrued liabilities as at December 31, 2021 (2020 - $23,000).

We have determined that our key management personnel consist of our executive officers and directors. Touchstone provides salaries and directors' fees, annual bonuses and other benefits to our key management personnel. In addition, we provide equity-based compensation to our key management personnel under our share option plan. Key management personnel compensation paid or payable during the years ended December 31, 2021 and 2020 are disclosed below.

($000's)	**Year ended December 31,**	
	2021	2020
Salaries and benefits included in G&A expenses	**1,265**	1,366
Director fees included in G&A expenses	**364**	225
Equity-based compensation	**722**	248
Key management compensation	**2,351**	1,839

The 2021 increase in key management compensation compared to 2020 was primarily attributable to increases in equity-based compensation, as the fair value of equity-based awards granted in 2020 and 2021 increased based on higher Company share prices versus previously granted awards.

The compensation paid to our non-executive directors during the year ended December 31, 2021 is set forth in the following table.

Director *($000's)*	**Fees earned**	**Equity-based compensation**	**All other compensation**	**Total compensation**
Kenneth R. McKinnon	52	51	8	**111**
Peter Nicol	50	47	8	**105**
Beverley Smith	50	61	8	**119**
Stanley T. Smith	52	49	8	**109**
Thomas E. Valentine	48	50	8	**106**
Dr. Harrie Vredenburg	48	42	8	**98**
John D. Wright	64	52	8	**124**
Director compensation	**364**	**352**	**56**	**772**

Changes in Accounting Policies Including Initial Adoption

There were no changes in accounting policies during the year ended December 31, 2021 that had a material effect on the reported comprehensive income (loss) or net assets of the Company.

Standards Issued but not yet Effective

There are no other standards or interpretations issued, but not yet adopted, that are anticipated to have a material effect on the future comprehensive income (loss) or net assets of the Company.

Significant Accounting Estimates, Judgements and Assumptions

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

A full list of the significant estimates and judgements made by Management in the preparation of our audited financial statements is included in Note 4 "*Use of Estimates, Judgements and Assumptions*" of the audited financial statements.

The Company has hired individuals who have the skills required to make such estimates and ensures that individuals or departments with the most knowledge of the activity are responsible for the estimates. Furthermore, past estimates are reviewed and compared to actual results, and actual results are compared to budgets in order to make more informed decisions on future estimates.

Control Environment

Management, including the Company's President and Chief Executive Officer and Chief Financial Officer, assessed the design and effectiveness of internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P") as at December 31, 2021. In making our 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 ICFR. Based on this evaluation, Management concluded that both ICFR and DC&P were effective as at December 31, 2021. There were no changes during the three months and year ended December 31, 2021 that had materially affected, or were reasonably likely to materially affect, ICFR.

ICFR is a process designed to provide reasonable assurance that all assets are safeguarded, and transactions are appropriately authorized to facilitate the preparation of relevant, reliable and timely information. Internal control systems, no matter how well designed, have inherent limitations and may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Furthermore, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Business Risks

For a full understanding of risks that affect Touchstone, the following should be read in conjunction with our 2021 Annual Information Form dated March 25, 2022, which can be found on our SEDAR profile (www.sedar.com) and website (www.touchstoneexploration.com). Refer to "*Advisory on Forward-Looking Statements*" in this MD&A for additional information regarding the risks to which Touchstone and our business operations are subject to.

As a participant in the international oil and natural gas industry, we are exposed to a variety of risks including, but not limited to, political, operational, financial, and environmental risks. As discussed in the "*Capital Management and Liquidity*" and "*Market Risk Management*" sections of this MD&A, we are exposed to normal financial risks inherent in the international oil and natural gas industry including commodity price risk, foreign exchange rate risk, credit risk and liquidity risk. The following are certain key risks, uncertainties and opportunities associated with the Company's business that can impact financial results.

Climate change

There is growing international concern regarding climate change, and there has been a significant increase in focus on the timing and pace of the transition to a lower-carbon economy. Greenhouse gas ("GHG") emissions legislation is emerging and is subject to change. Governments, financial institutions, insurance companies, environmental and governance organizations, institutional investors, social and environmental activists, and individuals are increasingly seeking to implement, among other things, regulatory and policy changes, changes in investment patterns, and modifications in energy consumption habits and trends, which individually and collectively are intended to or have the effect of accelerating the reduction in the global consumption of carbon-based energy, the conversion of energy usage to less carbon-intensive forms and the general migration of energy usage away from carbon-based forms of energy. The impact of such efforts requires Management to dedicate significant time and resources to these evolving climate-related change concerns and may adversely affect the Company's operations, the demand for and price of our crude oil and natural gas production, our cost of capital and access to capital markets. Further, climate change and its associated impacts may increase our exposure to, and magnitude of, each of the risks identified herein.

Pandemics

Global or domestic pandemics, epidemics or infectious disease outbreaks in the jurisdictions in which we operate, including COVID-19, Middle East Respiratory Syndrome, Severe Acute Respiratory Syndrome, H1N1 influenza virus, avian flu or any other similar illnesses, could have, without limitations, an adverse impact on our results, business, operations, financial condition, access to capital and liquidity, cost of borrowing, cash flows, reputation, business plans and/or the economy. The duration and the impact of a pandemic may also disrupt access to materials and services, increase employee absenteeism from illness and decrease commodity prices.

In March 2020, the World Health Organization declared COVID-19 a global pandemic, prompting many countries around the world to close international borders and order the closure of institutions and businesses deemed non-essential. This resulted in a swift and significant reduction in global economic activity along with a sudden drop in demand for crude oil and natural gas. While market conditions have improved, the full extent of the risks surrounding the COVID-19 pandemic is continually evolving in light of a global distribution of effective vaccines and through subsequent waves or additional variants of COVID-

19 continue to emerge which are more transmissible or cause more severe disease. The risks disclosed herein and our 2021 Annual Information Form may be exacerbated as a result of the COVID-19 pandemic; market risks related to the volatility of oil and gas prices, volatility of foreign exchange rates and volatility of the market price of our common shares; operational risks related to increasing operating expenses or declines in production levels, capital project delays, international shipping delays, delays in receiving government regulatory approvals, marketing arrangement counterparty performance or payment delays, and government regulations; ability to obtain additional financing, accounting adjustments, and effectiveness of internal controls; reliance on key personnel, management, and labour; and other risks related to cyber-security and protecting the integrity and functionality of our information technology systems, networks and data as our workforce in Canada and Trinidad may work from remote connections in response to COVID-19 and its variants.

The extent to which the COVID-19 pandemic continues to impact the Company's results, business, financial condition or liquidity will depend on global future developments and various factors and consequences which are beyond our control. Despite the approval of certain vaccines by global regulatory bodies, the ongoing evolution of the distribution of an effective vaccine in developing countries also continues to raise uncertainty, particularly its effect on local and global economic conditions that could influence the other risk factors identified herein, the extent of which is not yet known.

Russia-Ukraine conflict

In February 2022, Russian military forces invaded Ukraine. In response, Ukrainian military personal and civilians are actively resisting the invasion. Many countries throughout the world have provided assistance to Ukraine in the form of financial aid and in some cases military equipment and weapons to assist in their resistance to the invasion. The North Atlantic Treaty Organization ("NATO") has also mobilized forces to NATO member countries that are close to the conflict as deterrence to further Russian aggression in the region. The outcome of the conflict is uncertain and is likely to have wide-ranging consequences on the peace and stability of the region and the world economy. In addition, many countries including Canada, the United Kingdom and the United States, have imposed strict financial and trade sanctions against Russia, which sanctions may have material effects on the global economy and may make Russia default on its US$ denominated sovereign debt payments. As part of the sanctions package, the German government paused the certification process for the Nord Stream 2 natural gas pipeline that was built to carry natural gas from Russia to Germany. Russia is a major exporter of crude oil and natural gas, and disruption of supplies of crude oil and natural gas from Russia could cause a significant worldwide supply shortage and have a material effect on the prices of crude oil and natural gas and subsequently the global economy. The long-term impacts of the conflict and the sanctions imposed on Russia remain uncertain.

Foreign location of assets and foreign economic and political risk

Touchstone is subject to additional risks associated with international operations. Our operations may be adversely affected by changes in foreign government policies and legislation or social instability and other factors which are not within our control, including, but not limited to: nationalization, expropriation of property without fair compensation or marketable compensation; changes in laws and policies impacting foreign trade and investment; renegotiation or nullification of existing concessions and contracts; the imposition of specific drilling obligations and the development and abandonment of fields; changes in energy and environmental policies or the personnel administering them; changes in crude oil and natural gas pricing policies; the actions of national labour unions; currency fluctuations and devaluations; currency exchange controls; economic sanctions; taxation of the oil and natural gas sector; and other risks arising out of foreign governmental sovereignty over the areas in which Touchstone's operations are or will be conducted. If the Company's operations are disrupted and/or the economic integrity of its projects are threatened for unexpected reasons, its business may be harmed. Prolonged problems may threaten the commercial viability of our operations. In addition, there can be no assurance that contracts, licences, licence applications or other legal arrangements will not be adversely affected by changes in governments in foreign jurisdictions, the actions of government authorities or others, or the effectiveness and enforcement of such arrangements.

Although Management considers political conditions in Trinidad as generally stable, changes may occur in its political, fiscal and legal systems, which might affect the ownership or operation of our interests including, inter alia, changes in exchange rates, exchange control regulations, expropriation of crude oil and natural gas rights, changes in government and in legislative, fiscal and regulatory regimes. Our current business strategy, including our risk management strategies, has been formulated in the light of the current political and regulatory environment and likely future changes. The political and regulatory environment may change in the future, and such changes may have a material adverse effect on the Company.

Commodity prices and marketing

Numerous factors beyond our control do and will continue to affect the marketability and price of crude oil acquired, produced or discovered by the Company. Accordingly, commodity prices are the Company's most significant financial risk. Prices for crude oil are subject to large fluctuations in response to relatively minor changes in the supply of and demand, market uncertainty, and a variety of additional factors beyond our control. These factors include the impact of pandemics, economic and political conditions in the United States, Canada, Europe, Russia, China and emerging markets, the actions of Organization of Petroleum Exporting Countries ("OPEC") and other oil and gas exporting nations, governmental regulation, global political stability, the foreign supply and demand of crude oil, risks of supply disruption, the price of foreign imports, and the availability of alternative fuel sources. Crude oil prices may continue to be volatile for a variety reasons including market uncertainties over the supply and demand due to the current state of the global economy, the ongoing COVID-19 pandemic, OPEC and non-OPEC producers' actions in respect of supply, political uncertainties, slowing growth in emerging economies, weakening global relationships and trade relationships, sanctions imposed on certain oil producing nations by other countries and ongoing geopolitical conflicts, including the Russia-Ukraine conflict. Further, crude oil prices are also subject to the availability of foreign markets and Heritage's ability to access such markets. We monitor market conditions and may selectively utilize derivative instruments to reduce our exposure to crude oil price movements. However, we are of the view that it is neither appropriate nor possible to eliminate 100 percent of our exposure to commodity price volatility.

In addition, we entered into a long-term fixed price natural gas sales agreement in 2020 with NGC, which contains options for price negotiations on each fifth anniversary of the initial production date. The price of natural gas in Trinidad is predominantly based on domestic supply and demand, with demand largely from domestic power generation and petrochemical facilities. There can be no guarantee that we may be able to negotiate future price increases for natural gas, and a material decline in future natural gas sales prices will result in a reduction of the Company's cash flow from operations and financial position.

These factors could result in a material decrease in our expected petroleum sales and a reduction in our crude oil and natural gas production, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of the Company's reserves, borrowing capacity, petroleum sales, profitability and cash flow from operations and may have a material adverse effect on our business, financial condition, results of operations and prospects.

Environmental regulations

We are subject to environmental laws and regulations that affect aspects of our past, present and future operations. Extensive environmental laws and regulations in Trinidad set various standards regulating certain aspects of health and environmental quality, including air emissions, noise pollution, water quality, wastewater discharges and the generation, transport and disposal of waste and hazardous substances; provide for penalties and other liabilities for the violation of such standards; and establish obligations to remediate current and former facilities and locations where operations are or have been conducted. In addition, special provisions may be appropriate or required in environmentally sensitive areas of operation. We adopt prudent and industry-recommended field operating procedures for all operations, as well as maintaining a robust health, safety and environmental program in order to protect the environment, our employees and consultants, and the general public.

These environmental laws and regulations impose certain costs and risks on the Company, and there remain some uncertainty with regard to the impact of climate change and environmental laws and regulations on Touchstone, as we are unable to predict additional legislation or amendments that the Trinidadian government may enact in the future. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Company's operations and cash flows. Although we believe that we are in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on our business, financial condition, results of operations and prospects.

Operational matters

The operation of oil and gas wells and sales facilities may involve a number of operational and natural hazards. 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, environmental and safety concerns. The Company works to mitigate these risks by employing highly skilled personnel and utilizing available technology. We maintain a corporate insurance program in amounts consistent with industry practices to protect against insurable losses. Business interruption insurance may also be purchased for selected facilities, to the extent that such insurance is available. We may become liable for damages arising from such events against which we cannot insure or against which we may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities will reduce cash flows from operations and may reduce future capital investments. Furthermore, we may be subject to specific project risks that may be required to process and market our natural gas and NGL reserves.

The oil and 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, infrastructure and sales contracts, drilling and other specialized technical equipment and for experienced key human resources.

Sole purchasers and ability to market

We are exposed to sole purchaser risk in Trinidad as Heritage is the sole purchaser of crude oil production, and NGC will be the sole purchaser of future natural gas production. Our ability to market our petroleum and natural gas products depends upon numerous factors beyond our control, including: the availability of third-party pipeline capacity; the supply of and demand for petroleum and natural gas; the availability of alternative fuel sources; the counterparty's future financial viability; and the effects of weather conditions. Deliverability uncertainties relate to third-party processing and storage facilities, operational problems affecting pipelines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of crude oil, and domestic usage of natural gas. Because of these factors, we could be unable to market or to obtain competitive prices for the crude oil and natural gas we produce.

The amount of crude oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of these third-party processing facilities and pipeline systems and over which we do not have control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse effect on our ability to market our crude oil, natural gas and NGL production. The lack of availability of capacity in any of the third-party processing facilities and pipeline systems could result in our inability to realize the full economic potential of our production or in a material reduction of the price offered for our production. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as delays in constructing new infrastructure systems and facilities, could harm our business and, in turn, our financial condition, results of operations and cash flow from operations.

Reserves estimates

The reserves information included herein and in our annual independent reserves evaluation is only an estimate. Reserve values are based on a number of variables and assumptions such as future oil and natural gas prices, forecasted production volumes, forecasted operating and future development costs, and future governmental regulations. The actual production and ultimate reserves from our properties may be greater or less than the estimates prepared by our independent third-party reserves evaluator. Our reserves evaluator forecasts reserve volumes and future cash flows based upon current and historical well performance through to the economic production limit of individual wells. Notwithstanding established precedence and contractual options for the continuation and renewal of our existing licence, sub-licence and marketing agreements, in many cases the forecast economic limit of individual wells is beyond the current term of the relevant agreements, and there is no certainty as to any renewal of our existing production and marketing arrangements. Refer to the "*Oil and Natural Gas Reserves*" advisory section for further information.

Exploration

As a participant in the oil and gas industry, we are 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. Our current and future (to the extent discovered or acquired) proved reserves will decline as reserves are produced from our properties unless we can 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, we employ or contract highly qualified geologists, use technology such as seismic and current information system technology as primary exploration tools, and focus our exploration efforts in known hydrocarbon-producing basins. We may also choose to mitigate exploration risk through acquisitions that may require raising additional funds.

It is difficult to project the costs of implementing any exploratory drilling program due to the inherent uncertainties of drilling in unknown formations; the costs associated with encountering various drilling conditions such as unexpected formations or over pressured zones; premature declines of reservoirs and the invasion of water into producing formations; potential environmental damage, blow-outs, cratering, fires and spills, all of which could result in personal injuries, loss of life or threaten wildlife and damage to property of the Company and others; tools lost in the hole; and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

Trinidad exploration and production agreements

The current exploration and production licences, LOAs and joint operating agreements with respect to our properties contain significant obligations on the part of the Company's subsidiaries including minimum work commitments which, upon a continuing default, may give rise to the termination of our operatorship interest therein. There are no assurances that all of these commitments will be fulfilled within the time frames allowed. As such, we may lose certain exploration and production rights on the licence areas affected and may be subject to certain financial penalties that would be levied by Heritage, the MEEI, or the other parties thereto, as applicable. The current forms of licences and sub-licences, as applicable, may, in certain circumstances, be terminated at Heritage's or the MEEI's discretion and are subject to a defined term, and there is no certainty as to any renewal.

Further, the Company is operating under a number of private lease agreements which have expired and are currently being renegotiated. Based on opinions obtained from Trinidad legal counsel, the Company is continuing to recognize petroleum sales as operator and is paying all associated royalties and taxes, and no title to our land in Trinidad has been disputed. However, there is no certainty that such expired lease agreements will be renewed, on terms satisfactory to the Company or at all, or that our rights as operator will not be disputed. Refer to "*Principal Properties and Licences"* for further information.

Selected Quarterly Information

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

Three months ended	December 31, 2021	September 30, 2021	June 30, 2021	March 31, 2021
Operational				
Average daily production *(bbls/d)*	**1,336**	1,333	1,402	1,297
Net wells drilled	**3.0**	0.8	-	-
Brent benchmark price[(1)] *($/bbl)*	**79.61**	73.51	68.98	61.04
Operating netback[(2)] *($/bbl)*	**29.96**	27.77	26.30	21.98
Financial *($000's except per share amounts)*				
Petroleum sales	**8,212**	7,650	7,586	6,120
Cash from (used in) operating activities	**1,388**	384	1,008	(1,234)
Funds flow from operations	**1,291**	1,073	1,205	538
Per share – basic and diluted[(2)]	**0.01**	0.01	0.01	0.00
Net earnings (loss)	**6,514**	(51)	(284)	(460)
Per share – basic and diluted	**0.03**	(0.00)	(0.00)	(0.00)
Exploration capital expenditures	**2,946**	7,542	6,664	2,954
Development capital expenditures	**5,190**	2,315	125	127
Total capital expenditures	**8,136**	9,857	6,789	3,081
Working capital (surplus) deficit[(2)]	**(6,925)**	4,657	(4,671)	(10,552)
Principal long-term balance of term loan	**27,000**	7,125	7,500	7,500
Net debt (surplus)[(2)] – end of period	**20,075**	11,782	2,829	(3,052)
Share Information *(000's)*				
Weighted average – basic	**210,732**	210,732	209,757	209,400
Weighted average – diluted	**218,102**	210,732	209,757	209,400
Outstanding shares – end of period	**210,732**	210,732	210,732	209,400

Notes:
(1) Dated Brent average for the quarterly periods indicated. Source: US Energy Information Administration.
(2) Non-GAAP financial measure. See the "*Non-GAAP Financial Measures*" advisory section of this MD&A for further information.

Three months ended	December 31, 2020	September 30, 2020	June 30, 2020	March 31, 2020
Operational				
Average daily production *(bbls/d)*	1,274	1,310	1,396	1,589
Net wells drilled	1.6	-	-	-
Brent benchmark price(1) *($/bbl)*	44.32	42.91	29.70	50.27
Operating netback(2) *($/bbl)*	13.90	14.09	10.73	18.61
Financial *($000's except per share amounts)*				
Petroleum sales	4,414	4,725	3,755	6,698
Cash from (used in) operating activities	167	4,126	(1,921)	(76)
Funds flow (used in) from operations	(736)	192	(450)	1,257
Per share – basic and diluted(2)	(0.00)	0.00	(0.00)	0.01
Net earnings (loss)	1,655	(703)	(2,742)	(9,240)
Per share – basic and diluted	0.01	(0.00)	(0.01)	(0.05)
Exploration capital expenditures	9,031	5,758	1,249	1,823
Development capital expenditures	186	211	92	220
Total capital expenditures	9,217	5,969	1,341	2,043
Working capital surplus(2)	(12,933)	(869)	(6,534)	(8,094)
Principal long-term balance of term loan	7,500	15,000	15,000	13,338
Net (surplus) debt(2) – end of period	(5,433)	14,131	8,466	5,244
Share Information *(000's)*				
Weighted average – basic	197,686	184,277	183,640	169,361
Weighted average – diluted	206,072	184,277	183,640	169,361
Outstanding shares – end of period	209,400	184,408	184,161	183,489

Notes:
(1) Dated Brent average for the quarterly periods indicated. Source: US Energy Information Administration.
(2) Non-GAAP financial measure. See the "*Non-GAAP Financial Measures*" advisory section of this MD&A for further information.

The oil and natural gas exploration and production industry is cyclical. Our financial position, results of operations and cash flows are principally impacted by production levels and commodity prices, particularly crude oil prices. Commodity price fluctuations can indirectly impact expected production by changing the amount of funds available to reinvest in exploration, development and acquisition activities in the future. Changes in commodity prices impact revenue and cash flow available for exploration and development and also the economics of potential capital projects as low commodity prices can potentially reduce the quantities of reserves that are commercially recoverable. Our capital program is dependent on cash flow generated from operations and access to capital markets.

The following significant items impacted our unaudited financial and operating results over the past eight fiscal quarters:

- Touchstone generated $1.3 million in funds flow from operations in the fourth quarter of 2021, as production was consistent and realized crude oil pricing increased by 7 percent from the prior quarter. We increased our net debt by $8.3 million from the third quarter of 2021, as $8.1 million was invested in exploration and development drilling activities. Further, we increased our term loan balance from $20 million to $30 million and withdrew the remaining $15 million available balance on December 30, 2021. Net impairment reversals of $13.7 million and the associated deferred income tax expense impact of $7.2 million led to net earnings of $6.5 million reported in the quarter.
- In the third quarter of 2021, we maintained base crude oil production levels and generated $1.1 million in funds flow from operations. Capital expenditures increased from the prior quarter, as we drilled an exploration well and incurred rig mobilization and inventory costs for our fourth quarter

2021 development drilling program. The increased capital activity in the quarter led to a $9 million increase in net debt from the second quarter of 2021.

- We generated $1.2 million in funds flow from operations in the second quarter of 2021, reflecting 13 percent and 8 percent increases in realized crude oil pricing and production from the first quarter of 2021, respectively. Ortoire E&E investment was $6.7 million, resulting in a net debt balance of $2.8 million.
- In the first quarter of 2021, Touchstone reported $0.5 million in funds flow from operations predominantly from increased production and realized pricing from the fourth quarter of 2020. We proceeded with our Ortoire exploration activities, incurring a total of $3.1 million in capital expenditures. As a result, net surplus decreased by $2.4 million from the fourth quarter of 2020.
- Touchstone completed a private placement that resulted in net proceeds of $28.4 million in the fourth quarter of 2020. As a result, we prepaid $7.5 million of our term loan balance and increased E&E capital expenditures in the quarter, ending the quarter with a net surplus of $5.4 million. Predominately based on increased crude oil future pricing, net impairment reversals of $7.8 million were recorded. The impairment reversals, which were partially offset by related $3.9 million deferred income tax expenses, contributed to the Company recognizing net earnings of $1.7 million in the quarter.
- In the third quarter of 2020, net debt increased by $5.7 million or 67 percent from the second quarter of 2020, reflective of $5.8 million in E&E investments in the quarter. Average crude oil pricing increased by 34 percent from the prior quarter, which contributed to a $0.6 million increase in funds flow from operations to $0.2 million.
- Based on crude oil demand declines caused by COVID-19, second quarter 2020 realized crude oil pricing decreased by 36 percent from the prior quarter. Reduced expenditures on field operations also reduced crude oil production by 12 percent from the first quarter of 2020. These combined effects decreased second quarter operating netbacks by 42 percent, resulting in $0.5 million in funds flow used in operations. We invested $1.3 million in E&E activities which was the main driver in the increase in net debt of $3.2 million or 61 percent from the first quarter of 2020.
- In the first quarter of 2020, we recognized PP&E impairments of $19.2 million as a result of decreased forecasted crude oil pricing from the market effects of COVID-19. The impairments were slightly offset by an associated deferred income tax recovery of $10.1 million, resulting in a net loss of $9.2 million reported in the quarter. We completed a private placement in February 2020 for net proceeds of $10.9 million, which increased working capital and decreased net debt as of March 31, 2020.

Advisory

Non-GAAP Financial Measures

This MD&A or documents referred to in this MD&A make reference to various non-GAAP financial measures, non-GAAP ratios, capital management measures and supplementary financial measures as such terms are defined in National Instrument 52-112 - *Non-GAAP and Other Financial Measures Disclosure*. Such measures are not recognized measures under GAAP and do not have a standardized meaning prescribed by IFRS and therefore may not be comparable to similar financial measures disclosed by other issuers. Readers are cautioned that the non-GAAP financial measures referred to herein should not be construed as alternatives to, or more meaningful than measures prescribed by IFRS and they are not meant to enhance the Company's reported financial performance or position. These are complementary measures that are commonly used in the oil and natural gas industry and by the Company to provide shareholders and potential investors with additional information regarding the Company's performance, liquidity and ability to generate funds to finance its operations. Below is a description of the non-GAAP financial measures, non-GAAP ratios, capital management measures and supplementary financial measures disclosed in this MD&A.

Funds flow from operations and funds flow from operations per share

Funds flow from operations is included in the Company's consolidated statements of cash flows. Touchstone considers funds flow from operations to be a key measure of operating performance as it demonstrates the Company's ability to generate the funds necessary to finance capital expenditures and repay debt. Management believes that by excluding the temporary impact of changes in non-cash operating working capital, funds flow from operations provides a useful measure of the Company's ability to generate cash that is not subject to short-term movements in non-cash operating working capital.

Funds flow from operations per share is a non-GAAP ratio calculated by dividing funds flow from operations by the weighted average number of common shares outstanding during the applicable period on a basic and dilutive basis.

Operating netback

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

($000's unless otherwise stated)	**Three months ended December 31,**		**Year ended December 31,**	
	2021	2020	**2021**	2020
Petroleum sales	**8,212**	4,414	**29,568**	19,592
Royalties	**(2,723)**	(1,228)	**(9,251)**	(5,488)
Operating expenses	**(1,807)**	(1,556)	**(7,286)**	(6,698)
Operating netback	**3,682**	1,630	**13,031**	7,406
Production *(bbls)*	**122,917**	117,209	**490,741**	511,047
Operating netback *($/bbl)*	**29.96**	13.90	**26.55**	14.49

The following table reconciles funds flow from operations to operating netback for the periods indicated.

($000's)	**Three months ended December 31,**		**Year ended December 31,**	
	2021	2020	**2021**	2020
Funds flow from (used in) operations	**1,291**	(736)	**4,107**	263
Other revenue	**(5)**	(30)	**(40)**	(121)
Expenses				
G&A	**1,404**	2,207	**6,301**	5,574
Net finance	**630**	972	**1,437**	3,735
Current income tax	**208**	(65)	**1,358**	274
Realized foreign exchange	**424**	(38)	**473**	73
Change in non-cash other	**(270)**	(680)	**(614)**	(2,392)
Decommissioning expenditures	**-**	-	**9**	-
Operating netback	**3,682**	1,630	**13,031**	7,406

Working capital, net debt, total managed capital, net debt to funds flow from operations ratio and net debt to total managed capital ratio

Touchstone closely monitors its capital structure with a goal of maintaining a strong financial position to fund current operations and future growth. These are capital management measures used by Management to steward the Company's overall debt position and as measures of overall financial strength.

Management monitors working capital and net debt as part of the Company's capital structure to assess its true debt and liquidity position and to manage capital and liquidity risk. Working capital is calculated as current assets minus current liabilities as they appear on the consolidated statements of financial position. Net debt (surplus) is calculated by summing the Company's working capital and the principal (undiscounted) long-term amount of senior secured debt. The following table summarizes working capital and net debt (surplus) for the periods indicated.

($000's)	**December 31, 2021**	December 31, 2020
Current assets	**(27,856)**	(29,312)
Current liabilities	**20,931**	16,379
Working capital surplus	**(6,925)**	(12,933)
Principal long-term balance of term loan	**27,000**	7,500
Net debt (surplus)	**20,075**	(5,433)

The following table reconciles total liabilities to net debt (surplus) for the periods indicated.

($000's)	**December 31, 2021**	December 31, 2020
Total liabilities	**75,462**	44,187
Lease liabilities	**(2,265)**	(335)
Other liabilities	**(908)**	(1,357)
Decommissioning liabilities	**(10,012)**	(11,919)
Deferred income tax liability	**(14,450)**	(7,021)
Variance between carrying and principal value of term loan	**104**	324
Current assets	**(27,856)**	(29,312)
Net debt (surplus)	**20,075**	(5,433)

The Company's forward net debt to funds flow from operations ratio is the desired target Touchstone strives to achieve and maintain in a normalized commodity price environment. This ratio may increase at certain times as a result of increased capital expenditures or low commodity prices.

Management defines total managed capital as the sum of net debt (surplus) and shareholders' equity. The Company's forward net debt to total managed capital ratio is the desired target that the Company strives to maintain, as Management's strategy is to utilize more equity than debt.

Supplementary Financial Measures

The following supplementary financial measures are disclosed herein.

Realized sales price per barrel - is comprised of petroleum sales as determined in accordance with IFRS, divided by the Company's total crude oil and NGL sales volumes.

Royalties per barrel - is comprised of royalties as determined in accordance with IFRS, divided by the Company's total crude oil and NGL sales volumes.

Royalties as a percentage of petroleum sales - is comprised or royalties as determined in accordance with IFRS, divided by petroleum sales as determined in accordance with IFRS.

Operating expenses per barrel - is comprised of operating expenses as determined in accordance with IFRS, divided by the Company's total crude oil and NGL sales volumes.

G&A expenses per barrel - is comprised of G&A expenses as determined in accordance with IFRS, divided by the Company's total crude oil and NGL sales volumes.

Depletion expense per barrel - is comprised of depletion expenses as determined in accordance with IFRS, divided by the Company's total crude oil and NGL sales volumes.

Forward-Looking Statements

Certain information provided in this MD&A, including documents incorporated by references herein, may constitute forward-looking statements and information (collectively, "forward-looking statements") within the meaning of applicable securities laws. All statements and information, other than statements of historical fact, made by Touchstone that address activities, events, or developments that the Company expects or anticipates will or may occur in the future are forward-looking statements.

Such forward-looking statements include, without limitation, forecasts, estimates, expectations and objectives for future operations that are subject to assumptions, risks and uncertainties, many of which are beyond the control of the Company. Forward-looking statements are statements that are not historical facts and are generally, but not always, identified by the words "expects", "plans", "anticipates", "believes", "intends", "estimates", "projects", "potential" and similar expressions, or are events or conditions that "will", "would", "may", "could" or "should" occur or be achieved. Readers are cautioned that the assumptions used in the preparation of such forward-looking statements, 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.

In particular, forward-looking statements contained in this MD&A may include, but are not limited to, the Company's internal projections, estimates or expectations with respect to the following:

- the Company's business and operational strategies, including targeted jurisdictions and technologies used to execute its strategies;
- financial condition and outlook and results of operations, including expectations of future growth;
- the potential magnitude of future impacts from the COVID-19 pandemic, its potential effect on crude oil pricing and the Company's future operations;
- future demand for the Company's petroleum and natural gas products and economic activity in general;
- the magnitude of and ability to recover crude oil, natural gas and NGL reserves;
- the quantity and estimated future net revenue from oil, natural gas and NGL reserves and the projections of market prices and costs;
- the Company's future capital expenditure programs, including the anticipated timing of completion, allocation and costs thereof and the method of funding;
- the Company's estimated timing of development and ultimate production from its Ortoire wells;
- current and future crude oil, natural gas and NGL production levels and estimated field production levels;
- well production testing results, interpretations of wireline logging data and potential future production rates forecasted therefrom;
- the performance characteristics of the Company's oil and natural gas properties;
- expectations regarding the ability of the Company to raise capital and to continually add to reserves through exploration, acquisitions and development;

- future development and exploration activities to be undertaken in various areas and timing thereof, including future cash flows to be derived therefrom and the fulfillment of minimum work obligations and exploration commitments;
- terms and estimated future expenditures of the Company's contractual commitments and their timing of settlement;
- forecasted differential to Dated Brent reference pricing realized in the future;
- terms and title of exploration and production licences and the expected renewal of certain contracts;
- the Company's expectations regarding its ability to obtain contract extensions or fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its undeveloped properties;
- receipt of anticipated and future regulatory approvals or exploration and production licence amendments;
- access to third-party facilities and infrastructure;
- expected levels of operating expenses, G&A expenses, finance expenses and other costs associated with the Company's business;
- the Company's risk management strategy and the future use of commodity derivatives to manage commodity price risk;
- treatment under current and future governmental regulatory regimes, environmental legislation, royalty regimes and tax laws enacted in the Company's areas of operations;
- the Company's ability to reverse non-financial asset impairments in the future;
- foreign currency risk and the ability to reverse unrealized foreign exchange gains and losses in the future;
- the Company's future liquidity and future sources of liquidity;
- the Company's future compliance with its term loan covenants and its ability to make future scheduled interest and principal payments;
- estimated amounts of the Company's future obligations in connection with its production liability and its ability to make such future scheduled payments;
- the potential of future acquisitions or dispositions, including receiving regulatory approvals related thereto;
- general economic and political developments in Trinidad;
- estimated amounts, timing and the anticipated sources of funding for the Company's decommissioning liabilities;
- effect of business and environmental risks on the Company; and
- the statements under "*Significant Accounting Estimates, Judgements and Assumptions*".

Although the Company believes that the expectations reflected in the forward-looking statements are reasonable, it cannot guarantee future results, levels of activity, performance or achievement since such expectations are inherently subject to significant business, economic, operational, competitive, political and social uncertainties and contingencies, many of which are beyond the Company's control.

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, extreme weather-related events, and commodity and marketing risk. The Company is subject to significant drilling risks and uncertainties including the ability to find crude oil and natural gas reserves on an economic basis and the potential for technical problems that could lead to well blow-outs and environmental damage. The Company is exposed to risks relating to the inability to obtain timely regulatory approvals, surface access, access to third-party gathering and processing facilities, transportation and other third-party operation risks. The Company is subject to industry conditions including changes in laws and regulations, the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced. There are uncertainties in estimating the Company's reserve base due to the complexities in estimated future production, costs and timing of expenses and future capital. The Company is subject to the risk that it will not be able to fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its properties. The financial risks the Company is exposed to include, but are not limited to, the impact of general economic conditions in Canada, the United Kingdom and Trinidad, the impact of significant volatility in market prices for crude oil, the ability to access sufficient capital from internal and external sources, changes in income tax laws, royalties and incentive programs relating to the Trinidad oil and natural gas industry, fluctuations in interest rates, and fluctuations in foreign exchange rates. The Company is subject to local regulatory legislation, the compliance with which may require significant expenditures and non-compliance with which may result in fines, penalties or production restrictions or the termination of licence, exploration, lease operating or joint operating rights related to the Company's petroleum interests in Trinidad. Readers are cautioned that the foregoing list of risk factors is not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed under the Company's profile on SEDAR (www.sedar.com).

Management has included the above summary of assumptions and risks related to forward-looking statements and other information provided in this MD&A in order to provide shareholders and investors with a more complete perspective on the Company's current and future operations, and such information may not be appropriate for other purposes. Actual results, performance or achievement could differ materially from that expressed in or implied by any forward-looking statements in this MD&A, and accordingly, investors should not place undue reliance on any such forward-looking statements. Statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions that the reserves described can be profitably produced in the future.

Any forward-looking statement is made only as of the date of this MD&A, and Touchstone undertakes no obligation to update or revise any forward-looking statement or statements to reflect information, events, results, circumstances or otherwise after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as required by law, including applicable securities laws. New factors emerge from time to time, and it is not possible for Touchstone to predict all of such factors or to assess in advance the impact of each such factor on Touchstone's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

All forward-looking statements and information contained in this MD&A are expressly qualified by this cautionary statement.

Readers are further cautioned that the preparation of consolidated financial statements in accordance with IFRS requires Management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. These estimates may change, having either a positive or negative effect on net earnings (loss), as further information becomes available and as the economic environment changes.

Oil and Natural Gas Reserves

Touchstone's year-end crude oil, natural gas and NGL reserves in Trinidad were evaluated by independent reserves evaluator, GLJ, in accordance with definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook and NI 51-101. The disclosure in this MD&A highlights certain information contained in the Reserves Report but represents only a portion of the disclosure required under NI 51-101. Full disclosure and related advisories with respect to the Company's reserves as at December 31, 2021 is included in the Company's 2021 Annual Information Form dated March 25, 2022, which can be accessed online on the Company's SEDAR profile (www.sedar.com) or the Company's website (www.touchstoneexploration.com).

There are numerous uncertainties inherent in estimating quantities of crude oil and natural gas reserves. The recovery, reserve estimates of crude oil and natural gas reserves provided herein are estimates only, and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein. The estimates of reserves for individual properties disclosed herein may not reflect the same confidence levels as estimates of reserves for all properties, due to the effects of aggregation.

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

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

Oil and Natural Gas Measures

Where applicable, natural gas has been converted to barrels of oil equivalent based on six thousand cubic feet to one barrel of oil. The barrel of oil equivalent rate is based on an energy equivalent conversion method primarily applicable at the burner tip, and given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different than the energy equivalency of the 6:1 conversion ratio, utilizing the 6:1 conversion ratio may be misleading as an indication of value.

References to Touchstone

For convenience, references in this document to the "Company", "we", "us", "our", and "its" may, where applicable, refer only to Touchstone.

Abbreviations

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

Oil and gas measurement

bbl(s)	barrel(s)
bbls/d	barrels per day
Mbbls	thousand barrels
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MMBtu	million British Thermal Units
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Mboe	thousand barrels of oil equivalent

Other

AIM	AIM market of the London Stock Exchange plc
API	American Petroleum Institute gravity
Brent	Dated Brent
C$	Canadian dollar
NGL(s)	Natural gas liquid(s)
psi	Pounds per square inch
TSX	Toronto Stock Exchange
TT$	Trinidad and Tobago dollar
WTI	Western Texas Intermediate
$ or US$	United States dollar
£	Pounds sterling

Corporate Information

Directors
John D. Wright
Chair of the Board

Paul R. Baay
Kenneth R. McKinnon
Peter Nicol
Beverley Smith
Stanley T. Smith
Thomas E. Valentine
Harrie Vredenburg

Officers and Senior Executives
Paul R. Baay
President and Chief Executive Officer

Scott Budau
Chief Financial Officer

James Shipka
Chief Operating Officer

Brian Hollingshead
Vice President Engineering and Business Development

Alex Sanchez
Vice President Production and Environment

Cayle Sorge
Vice President Finance

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Stock Exchange Listing
Toronto Stock Exchange
London Stock Exchange AIM
Symbol: TXP

Auditor
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Calgary, Alberta

Reserves Evaluator
GLJ Ltd.
Calgary, Alberta

Legal Counsel
Norton Rose Fulbright LLP
Calgary, Alberta
London, United Kingdom

Nunez and Co.
Port of Spain, Trinidad

Transfer Agent and Registrar
Odyssey Trust Company
Calgary, Alberta

Link Group
London, United Kingdom

UK Nominated Advisor and Joint Broker
Shore Capital
London, United Kingdom

UK Joint Broker
Canaccord Genuity
London, United Kingdom

UK Public Relations
Camarco
London, United Kingdom