

CONSOLIDATED INTERIM FINANCIAL STATEMENTS
Consolidated Balance Sheets (unaudited)

As at (thousands of United States dollars)	NOTE	September 30, 2017	December 31, 2016
ASSETS			
Current assets			
Cash and cash equivalents		\$ 195,870	\$ 149,246
Accounts receivable	5	69,158	46,019
Prepays and other current assets		3,326	2,502
Crude oil inventory	6	2,072	2,834
		270,426	200,601
Deferred tax asset	14	21,256	17,324
Goodwill		73,452	73,452
Exploration and evaluation	7	116,277	101,024
Property, plant and equipment	8	576,448	526,270
		\$ 1,057,859	\$ 918,671
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities		\$ 90,953	\$ 86,313
Derivative financial instruments	18	320	1,704
Current income and equity tax payable	14	27,959	8,404
Current portion of decommissioning and environmental liabilities	11	10,902	10,890
		130,134	107,311
Other long-term liabilities	10	5,274	1,652
Decommissioning and environmental liabilities	11	42,290	40,256
Deferred tax liability	14	48,003	55,660
		225,701	204,879
Shareholders' equity			
Share capital	12	832,880	822,227
Contributed surplus		51,018	42,208
Deficit		(51,740)	(150,643)
		832,158	713,792
		\$ 1,057,859	\$ 918,671

Commitments (note 20)

See accompanying Notes to the Consolidated Interim Financial Statements

Approved by the Board:



 Paul Wright
Director



 Ron Miller
Director

Consolidated Statements of Comprehensive Income (Loss) (unaudited)

(thousands of United States dollars, except per share amounts)	NOTE	For the three months ended September 30,		For the nine months ended September 30,	
		2017	2016	2017	2016
Oil and natural gas sales		\$ 159,929	\$ 127,541	\$ 455,477	\$ 313,630
Royalties		(13,015)	(8,927)	(38,688)	(23,967)
Revenue		146,914	118,614	416,789	289,663
Commodity risk management contracts gain (loss)	18	(2,295)	2,850	114	(9,281)
		144,619	121,464	416,903	280,382
Expenses					
Production		18,191	12,341	49,943	37,886
Transportation		35,678	32,843	103,781	99,442
Purchased oil		942	16,569	4,228	20,939
General and administrative		8,943	6,759	25,082	23,853
Legal settlement		—	—	15,000	—
Equity settled share-based compensation	12	4,866	3,180	14,637	9,011
Cash settled share-based compensation	13	2,962	6,580	3,763	11,526
Depletion, depreciation and amortization	8	28,755	31,917	79,070	92,644
Foreign exchange (gain) loss		1,149	176	206	(284)
		101,486	110,365	295,710	295,017
Finance (income)	9	(624)	(81)	(1,500)	(962)
Finance expense	9	1,993	1,416	6,597	5,806
Net finance expense		1,369	1,335	5,097	4,844
Income (loss) before income taxes		41,764	9,764	116,096	(19,479)
Income tax expense (recovery)					
Current tax expense	14	16,166	1,951	28,528	1,657
Deferred tax expense (recovery)	14	(29,929)	1,002	(11,589)	(20,132)
		(13,763)	2,953	16,939	(18,475)
Net income (loss) and comprehensive income (loss) for the period		\$ 55,527	\$ 6,811	\$ 99,157	\$ (1,004)
Basic net income (loss) per common share	15	\$ 0.36	\$ 0.04	\$ 0.64	\$ (0.01)
Diluted net income (loss) per common share	15	\$ 0.35	\$ 0.04	\$ 0.63	\$ (0.01)

See accompanying Notes to the Consolidated Interim Financial Statements



Consolidated Statements of Changes in Equity (unaudited)

For the nine months ended September 30,
(thousands of United States dollars)

	2017		2016
Share capital			
Balance, beginning of period	\$ 822,227	\$	812,737
Issuance of common shares under share-based compensation plans	10,817		7,304
Repurchase of shares	(164)		—
Balance, end of period	832,880		820,041
Contributed surplus			
Balance, beginning of period	42,208		33,388
Share-based compensation	14,637		9,011
Options exercised	(4,431)		(2,925)
Contributed surplus attributed to DSUs transferred to cash settled liability	(1,396)		—
Balance, end of period	51,018		39,474
Deficit			
Balance, beginning of period	(150,643)		(104,199)
Net income (loss) for the period	99,157		(1,004)
Repurchase of shares	(254)		—
Balance, end of period	(51,740)		(105,203)
	\$ 832,158	\$	754,312

See accompanying Notes to the Consolidated Interim Financial Statements



Consolidated Statements of Cash Flows (unaudited)

(thousands of United States dollars)	NOTE	For the three months ended September 30,		For the nine months ended September 30,	
		2017	2016	2017	2016
Operating activities					
Net income (loss)		\$ 55,527	\$ 6,811	\$ 99,157	\$ (1,004)
Add (deduct) non-cash items					
Depletion, depreciation and amortization	8	28,755	31,917	79,070	92,644
Non-cash finance expense	9	959	463	2,968	1,303
Equity settled share-based compensation	12	4,866	3,180	14,637	9,011
Cash settled share-based compensation (recovery)	13	2,962	6,580	3,763	11,526
Deferred tax expense (recovery)	14	(29,929)	1,002	(11,589)	(20,132)
Unrealized foreign exchange loss (gain)		952	(85)	2,378	(1,880)
Unrealized loss (gain) on commodity risk management contracts	18	2,120	(3,743)	(1,117)	3,702
Abandonment costs paid		(38)	(10)	(319)	(84)
Stock appreciation rights paid		(176)	(1,024)	(3,281)	(2,746)
Funds flow provided by operations		65,998	45,091	185,667	92,340
Net change in non-cash working capital	16	(15,561)	10,162	(2,055)	(21,538)
Cash provided by operating activities		50,437	55,253	183,612	70,802
Investing activities					
Property, plant and equipment expenditures	8	(26,760)	(14,329)	(104,755)	(30,360)
Exploration and evaluation expenditures	7	(24,674)	(11,984)	(41,250)	(14,382)
Net change in non-cash working capital	16	(6,491)	7,016	3,537	5,988
Cash (used in) investing activities		(57,925)	(19,297)	(142,468)	(38,754)
Financing activities					
Issuance of common shares under option plans	12	716	1,622	6,386	4,378
Common shares repurchased		(418)	—	(418)	—
Cash provided by financing activities		298	1,622	5,968	4,378
Increase (decrease) in cash for the period		(7,190)	37,578	47,112	36,426
Impact of foreign exchange on foreign currency-denominated cash balances		164	38	(488)	806
Cash, beginning of period		202,896	94,439	149,246	94,823
Cash, end of period		\$ 195,870	\$ 132,055	\$ 195,870	\$ 132,055

Supplemental Disclosure of Cash Flow Information (note 16)
See accompanying Notes to the Consolidated Interim Financial Statements



Notes to the Condensed Interim Consolidated Financial Statements

For the period ended September 30, 2017

(Tabular amounts in thousands of United States dollars, unless otherwise stated. Amounts in text are in United States dollars unless otherwise stated.)

1. Corporate Information

Parex Resources Inc. and its subsidiaries ("Parex" or "the Company") are in the business of the exploration, development, production and marketing of oil and natural gas in Colombia.

Parex Resources Inc. is a publicly traded Company, incorporated and domiciled in Canada. Its registered office is at 2400, 525-8th Avenue S.W., Calgary, Alberta T2P 1G1. The Company was incorporated on August 17, 2009, pursuant to the Business Corporations Act (Alberta).

The condensed interim consolidated financial statements were approved and authorized for issuance by the Board of Directors on November 7, 2017.

2. Basis of Presentation and Adoption of International Financial Reporting Standards ("IFRS")

a) Statement of compliance

The condensed interim consolidated financial information for the three and nine months ended September 30, 2017 has been prepared in accordance with IAS 34, 'Interim financial reporting'. The condensed interim consolidated financial information should be read in conjunction with the annual financial statements for the year ended December 31, 2016, which have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB").

The policies applied in these condensed interim consolidated financial statements are based on IFRS issued and outstanding as of November 7, 2017, the date of approval by the Board of Directors.

b) Basis of measurement

The condensed interim consolidated financial statements have been prepared under the historical cost convention except for derivative financial instruments and share-based compensation transactions which are measured at fair value. The methods used to measure fair values are discussed in note 4 - Determination of Fair Values.

c) Use of management estimates, judgments and measurement uncertainty

The timely preparation of the condensed interim consolidated financial statements requires that management make estimates and use judgment regarding the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as at the date of the condensed interim consolidated financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as at the date of the condensed interim consolidated financial statements. Accordingly, actual results could differ from estimated amounts as future confirming events occur.

In preparing these condensed interim consolidated financial statements, the significant judgements made by management in applying the group's accounting policies and the key sources of estimation uncertainty were the same as those that applied to the consolidated financial statements for the year ended December 31, 2016.

3. Summary of Significant Accounting Policies

There is no impact on the condensed interim consolidated financial statements for the adoption of new accounting standards effective January 1, 2017. The accounting policies adopted are consistent with those of the previous financial year as described in note 3 of the Company's consolidated financial statements for the year ended December 31, 2016, except for the following:

Pursuant to the Restricted Share Unit ("RSU") plan, the Company may grant Performance Share Units ("PSUs") to certain employees. Compensation cost attributable to PSUs granted to certain employees of the Company is measured at fair value at the date of grant and expensed over the vesting period with a corresponding increase in contributed surplus. The fair value of each PSU granted is based on the share price at which the common shares of the Company traded for on the grant date. The performance share units may be granted with certain performance measures, specified at the grant date as determined by the Company's Board of Directors. Based upon the achievement of the performance measures, a pre-determined adjustment factor of between 0-2x is applied to PSUs eligible to vest at the end of the performance period. The expense recognized over the vesting period of PSUs is the fair value of the PSUs with an estimated adjustment factor. If the actual final adjustment factor is higher



than estimated at grant, additional expense is recognized on vesting for the incremental fair value. Upon the exercise of the PSUs consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

The Company has a Cash Settled Restricted Share Unit ("CRSUs") plan which allows the Company to issue CRSUs to certain employees of Parex Colombia. Obligations for payments of cash under the foreign subsidiaries' CRSUs plan are accrued as compensation expense over the vesting period based on the fair value of CRSUs. The fair value of CRSUs is equal to the market price of the Company's common shares at the valuation date. In accordance with the fair value method, increases or decreases in the fair value of the CRSUs result in a corresponding change in the recorded liability. The accrued compensation for a right that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture. The CRSUs liability cannot be settled by the issuance of common shares.

In the current period the Company amended the terms of its Deferred Share Unit ("DSUs") plan which allows the Company to issue DSUs to certain non-employee directors of Parex Resources Inc. Previously DSUs were settled in shares or cash at the discretion of the Company. Going forward the DSUs will be settled in cash and the DSUs liability cannot be settled by the issuance of common shares. As DSUs vest immediately on issuance, obligations for payments of cash under the DSUs plan are accrued as compensation expense immediately on issuance based on the fair value of the DSUs. The fair value of DSUs at each reporting period is equal to the market price of the Company's common shares at the valuation date. In accordance with the fair value method, increases or decreases in the fair value of the DSUs result in a corresponding change in the recorded liability. The accrued compensation for a unit that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture.

Cash and cash equivalents comprise cash on hand and other short-term highly liquid investments with maturities less than 3 months.

In future accounting periods, the Company will adopt the following IFRS standards issued but not yet effective:

IFRS 15 Revenue from Contracts with Customers - IFRS 15 "Revenue from Contracts with Customers" was issued in May 2014 and replaces IAS 18 "Revenue", IAS 11 "Construction Contracts" and related interpretations. The standard is required to be adopted for fiscal years beginning on or after January 1, 2018 either retrospectively or using a modified transaction approach, with early adoption permitted. IFRS 15 will be adopted by the Company on January 1, 2018. IFRS 15 provides clarification for recognizing revenue from contracts with customers and establishes a single revenue recognition and measurement framework. The impact of the standard has been evaluated by the Company and is expected to have no material impact on the Company's financial statements. Additional disclosure may be required upon implementation of IFRS 15 in order to provide sufficient information to enable users to understand the nature, amount, timing, and uncertainty of revenue and cash flows arising from the contracts with customers.

IFRS 9 Financial Instruments - In July 2014, the IASB completed the final amendments of IFRS 9 "Financial Instruments". The Standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 "Financial Instruments: Recognition and Measurement". IFRS 9, as amended, includes a principle-based approach for classification and measurement of financial assets, a single 'expected loss' impairment model and a substantially-reformed approach to hedge accounting. The Standard will come into effect for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. This amendment will be adopted by the Company on January 1, 2018 and the Company does not expect the amendment to have a material impact on the Company's financial statements.

IFRS 16 Leases - IFRS 16 "Leases" was issued January 2016 and replaces IAS 17 "Leases". The standard introduces a single lessee accounting model for leases with required recognition of assets and liabilities for most leases. The standard is effective for fiscal years beginning on or after January 1, 2019 with early adoption permitted if the Company is also applying IFRS 15 "Revenue from Contracts with Customers". IFRS 16 will be adopted by the Company on January 1, 2019 and the Company is currently reviewing contracts that are identified as leases and assessing the impact that the adoption of the standard will have on the consolidated financial statements.

4. Determination of Fair Values

The methods used in the determination of fair value, for financial and non-financial assets and liabilities have not changed from the previous financial year. Refer to note 4 of the December 31, 2016 consolidated financial statements for details concerning determination of fair values.

5. Accounts Receivable

	September 30, 2017	December 31, 2016
Trade receivables	\$ 26,840	\$ 15,469
Colombia income taxes receivable	31,625	19,810
Value added taxes (VAT)	10,693	10,740
	\$ 69,158	\$ 46,019



Trade receivables consist primarily of oil sale receivables related to the Company's oil sales. Colombia income tax receivable is a result of withholding tax incurred on Colombia oil sales and tax installments. The balance can either be received in cash or applied to Colombian cash income tax payable. VAT receivable is \$10.7 million as at September 30, 2017 (December 31, 2016 - \$10.7 million) and is recoverable within one year. All accounts receivable are expected to be received within twelve months and are thus recognized as current assets.

6. Inventory

	September 30, 2017	December 31, 2016
Crude oil inventory	\$ 2,072	\$ 2,834

Crude oil inventory consists of crude oil in transit at the balance sheet date and is valued at the lower of cost using the weighted average cost method and net realizable value. Costs include direct and indirect expenditures incurred in bringing the crude oil to its existing condition and location.

7. Exploration and Evaluation Assets

	Colombia Total
Cost	
Balance, December 31, 2015	\$ 121,354
Additions	48,178
Changes in decommissioning liability	1,372
Exploration and evaluation impairment	(69,880)
Balance, December 31, 2016	\$ 101,024
Additions	41,250
Transfers to PP&E	(26,429)
Changes in decommissioning liability	432
Balance, September 30, 2017	\$ 116,277

Exploration and Evaluation ("E&E") assets consist of the Company's exploration projects which are pending either the determination of proved or probable reserves or impairment. Additions of \$41.3 million for the nine months ended September 30, 2017 represent the Company's share of costs incurred on E&E assets during the period. For the nine months ended September 30, 2017, \$26.4 million of E&E assets were transferred to PP&E related to the Aguas Blancas Block.

During the year ended December 31, 2016, additions of \$48.2 million represent the Company's share of costs incurred on E&E assets during the period. There were no E&E assets transferred to PP&E during the year ended December 31, 2016. Also in 2016, the Company recorded a \$69.9 million impairment charge related to Cerrero Block, Cebucan Block and Block LLA-24 in the Northern Llanos basin.

At September 30, 2017 the Company did not have E&E assets in Canada.

8. Property, Plant and Equipment

	Canada	Colombia	Total
Cost			
Balance, December 31, 2015	\$ 3,607	\$ 1,537,663	\$ 1,541,270
Additions	126	59,393	59,519
Additions related to property acquisition	—	4,025	4,025
Changes in decommissioning and environmental liability	—	13,042	13,042
Balance, December 31, 2016	\$ 3,733	\$ 1,614,123	\$ 1,617,856
Additions	28	104,727	104,755
Transfers from E&E assets	—	26,429	26,429
Changes in decommissioning and environmental liability	—	(2,114)	(2,114)
Balance, September 30, 2017	\$ 3,761	\$ 1,743,165	\$ 1,746,926

Accumulated Depreciation, Depletion and Amortization

Balance, December 31, 2015	\$ 3,062	\$ 963,895	\$ 966,957
Depletion and depreciation for the year	286	115,491	115,777
DD&A included in crude oil inventory costing	—	(745)	(745)
Impairment	—	9,597	9,597
Balance, December 31, 2016	\$ 3,348	\$ 1,088,238	\$ 1,091,586
Depletion and depreciation for the period	138	78,932	79,070
DD&A included in crude oil inventory costing	—	(178)	(178)
Balance, September 30, 2017	\$ 3,486	\$ 1,166,992	\$ 1,170,478

Net book value:

As at December 31, 2015	\$ 545	\$ 573,768	\$ 574,313
As at December 31, 2016	\$ 385	\$ 525,885	\$ 526,270
As at September 30, 2017	\$ 275	\$ 576,173	\$ 576,448

In the nine months ended September 30, 2017 property, plant and equipment ("PPE") additions of \$104.8 million mainly relate to drilling costs in Colombia at Block LLA-34, Cabrestero block, and the Aguas Blancas block. For the nine months ended September 30, 2017, \$26.4 million of E&E assets were transferred to PP&E related to the Aguas Blancas block (nine months ended September 30, 2016 - \$nil).

For the nine months ended September 30, 2017 future development costs of \$346.5 million (nine months ended September 30, 2016 - \$252.1 million) were included in the depletion calculation for development and production assets. For the nine months ended September 30, 2017 \$5.2 million of general and administrative costs (nine months ended September 30, 2016 - \$2.5 million) have been capitalized in respect of development and production activities during the current period.

During the year ended December 31, 2016, additions mainly related to development expenditures in the amount of \$59.5 million in Colombia at Block LLA-34 and exploration drilling on Block LLA-32 and Cabrestero. There were no transfers from E&E for the year ended December 31, 2016. Also in 2016, the Company recorded \$9.6 million of impairment charges related to the Block LLA-30 CGU.

There were no indicators of impairment noted as of September 30, 2017.

9. Net Finance Expense (Income)

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Bank charges and credit facility fees	\$ 1,036	\$ 953	\$ 2,737	\$ 2,275
Accretion on decommissioning and environmental liabilities	957	463	2,966	1,303
Interest and other income	(624)	(81)	(1,500)	(962)
Colombian net wealth tax	—	—	894	2,228
Net finance expense	\$ 1,369	\$ 1,335	\$ 5,097	\$ 4,844



	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Non-cash finance expense	\$ 957	\$ 463	\$ 2,966	\$ 1,303
Cash finance expense	412	872	2,131	3,541
Net finance expense	\$ 1,369	\$ 1,335	\$ 5,097	\$ 4,844

10. Other Long-Term Liabilities

Other long-term liabilities are comprised of the following:

	September 30, 2017	December 31, 2016
Long-term SARs payable	\$ 2,778	\$ 1,652
Long-term DSUs payable	2,061	—
Long-term CRSUs payable	435	—
	\$ 5,274	\$ 1,652

11. Decommissioning and Environmental Liabilities

	Decommissioning	Environmental	Total
Balance, December 31, 2015	\$ 26,811	\$ 8,588	\$ 35,399
Additions	5,241	703	5,944
Settlements of obligations during the year	(75)	(103)	(178)
Accretion expense	1,432	399	1,831
Additions related to change in estimate - inflation and discount rates	7,697	1,482	9,179
Additions related to change in estimate - costs	(2,386)	1,677	(709)
Foreign exchange (gain)	—	(320)	(320)
Balance, December 31, 2016	\$ 38,720	\$ 12,426	\$ 51,146
Additions	3,839	1,345	5,184
Additions related to change in estimate - inflation and discount rates	(5,467)	(1,399)	(6,866)
Settlements of obligations during the period	(160)	(159)	(319)
Accretion expense	1,895	1,071	2,966
Foreign exchange loss (gain)	1,172	(91)	1,081
Balance, September 30, 2017	\$ 39,999	\$ 13,193	\$ 53,192
Current obligation	(4,074)	(6,828)	(10,902)
Long-term obligation	\$ 35,925	\$ 6,365	\$ 42,290

The total environmental, decommissioning and restoration obligations were determined by management based on the estimated costs to settle environmental impact obligations incurred and to reclaim and abandon the wells and well sites based on contractual requirements. The obligations are expected to be funded from the Company's internal resources available at the time of settlement.

The total decommissioning and environmental liability is estimated based on the Company's net ownership in wells drilled as at September 30, 2017, the estimated costs to abandon and reclaim the wells and well sites and the estimated timing of the costs to be paid in future periods. The total undiscounted amount of cash flows required to settle the Company's decommissioning liability is approximately \$71.5 million as at September 30, 2017 (December 31, 2016 – \$92.1 million) with the majority of these costs anticipated to occur after 2029. A risk-free discount rate of 7.5 percent and an inflation rate of 4.0 percent were used in the valuation of the liabilities (December 31, 2016 – 7.2 percent risk-free discount rate and a 7.5 percent inflation rate). The risk-free discount rate and the inflation rate used in 2017 are based on forecast Colombia rates.

Included in the decommissioning liability is \$4.1 million (December 31, 2016 – \$4.2 million) that is classified as a current obligation.

The total undiscounted amount of cash flows required to settle the Company's environmental liability is approximately \$16.3 million as at September 30, 2017 (December 31, 2016 – \$16.1 million) with the majority of these costs anticipated to occur in 2018 or later in Colombia. A risk-free discount rate of 7.5 percent and an inflation rate of 4.0 percent were used in the valuation of the liabilities (December 31, 2016 – 7.2 percent risk-free discount rate and a 7.5 percent inflation rate). The risk-free discount rate and the inflation rate used in 2017 are based on forecast Colombia rates.

Included in the environmental liability is \$6.8 million (December 31, 2016 – \$6.7 million) that is classified as a current obligation.



12. Share Capital

a) Issued and outstanding common shares

	Number of shares	Amount
Balance, December 31, 2015	151,489,302 \$	812,737
Issued for cash – exercise of options and RSUs	1,501,193	5,492
Allocation of contributed surplus – exercise of options and RSUs	—	3,998
Balance, December 31, 2016	152,990,495 \$	822,227
Issued for cash – exercise of options and RSUs	1,602,778	6,386
Allocation of contributed surplus – exercise of options and RSUs	—	4,431
Repurchase of shares	(37,500)	(164)
Balance, September 30, 2017	154,555,773 \$	832,880

The Company has authorized an unlimited number of voting common shares without nominal or par value.

In the nine months ended September 30, 2017, a total of 1,602,778 options and RSUs were exercised for proceeds of \$6.4 million (year ended December 31, 2016 - 1,501,193 options and RSUs were exercised for proceeds of \$5.5 million).

In 2017, the Company repurchased 37,500 (nine months ended September 30, 2016 - nil) common shares pursuant to its Normal Course Issuer Bid at a cost of \$0.4 million (average cost per share of Cdn\$14.43). The cost to repurchase common shares at a price in excess of their average book value has been charged to retained earnings.

b) Stock options

The Company has a stock option plan which provides for the issuance of options to the Company's officers and certain employees to acquire common shares. The maximum number of options and restricted share units (including performance share units) reserved for issuance under the stock option and restricted share unit plans may not exceed 10 percent of the number of common shares issued and outstanding. The stock options vest over a three-year period and expire five years from the date of grant.

	Number of stock options	Weighted average exercise price Cdn\$/option
Balance, December 31, 2015	7,854,511	8.11
Granted	1,375,500	15.60
Exercised	(1,179,235)	6.07
Forfeited	(309,002)	9.80
Balance, December 31, 2016	7,741,774	9.68
Granted	666,500	15.88
Exercised	(1,283,686)	6.58
Forfeited	(44,417)	12.82
Balance, September 30, 2017	7,080,171	10.81

Stock options outstanding and the weighted average remaining life of the stock options at September 30, 2017 are as follows:

Exercise price Cdn\$	Options outstanding			Options vested		
	Number of options	Weighted average remaining life (years)	Weighted average exercise price Cdn\$/option	Number of options	Weighted average remaining life (years)	Weighted average exercise price Cdn\$/option
\$4.36 - \$6.31	1,894,270	1.03	\$ 6.02	1,894,270	1.03	\$ 6.02
\$6.32 - \$10.59	1,392,124	2.11	\$ 10.16	863,684	2.11	\$ 10.22
\$10.60 - \$11.24	1,746,401	3.11	\$ 10.94	537,395	3.11	\$ 10.94
\$11.25 - \$15.84	1,454,276	4.03	\$ 15.38	56,041	1.79	\$ 12.05
\$15.85 - \$16.87	593,100	4.43	\$ 16.05	—	—	—
	7,080,171	2.66	\$ 10.81	3,351,390	1.65	\$ 8.00



The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions:

For the nine months ended September 30,	2017	2016
Risk-free interest rate (%)	1.10	0.64
Expected life (years)	4	4
Expected volatility (%)	44	47
Forfeiture rate (%)	3	3
Expected dividends	—	—

The weighted average fair value at the grant date for the nine months ended September 30, 2017 was Cdn\$5.62 per option (nine months ended September 30, 2016 - Cdn\$4.30 per option). The weighted average share price on the exercise date for options exercised in the nine months ended September 30, 2017 was Cdn\$16.58 (nine months ended September 30, 2016 - Cdn\$13.26).

c) Restricted and performance share units

The Company has in place a restricted share unit plan pursuant to which the Company may grant restricted shares to certain employees. The restricted shares vest at 33 percent on each of the first, second and third anniversaries of the grant date and expire five years from date of grant.

	Number of RSU's	Weighted average exercise price Cdn\$/RSU
Balance, December 31, 2015	2,306,965	0.01
Granted	692,475	0.01
Exercised	(321,958)	0.01
Forfeited	(89,336)	0.01
Balance, December 31, 2016	2,588,146	0.01
Granted	632,550	0.01
Exercised	(319,092)	0.01
Forfeited	(21,584)	0.01
Balance, September 30, 2017	2,880,020	0.01

RSUs outstanding and the weighted average remaining life of the RSUs at September 30, 2017 are as follows:

Exercise price Cdn\$	RSUs outstanding		RSUs vested	
	Number of RSUs	Weighted average remaining life (years)	Number of RSUs	Weighted average remaining life (years)
0.01	2,880,020	3.29	773,466	2.08

The fair value of each RSU granted is based on the market price of Parex shares on the date of issuance. The weighted average fair value at the grant date for the nine months ended September 30, 2017 was Cdn\$15.99 per RSU (nine months ended September 30, 2016 - Cdn\$13.06 per RSU). For the nine months ended September 30, 2017 a weighted average forfeiture rate of 3% was applied (nine months ended September 30, 2016 - 3%).

Pursuant to the restricted share unit plan, the Company may grant performance share units to certain employees. The performance share units vest three years after the grant date and expire one month after the vesting date. The vesting of PSUs is conditional on the satisfaction of certain performance criteria as determined by the Company's Board of Directors. If the Company satisfies the performance criteria, PSUs become eligible to vest and a pre-determined multiplier is applied to eligible PSUs.

	Number of PSU's	Weighted average exercise price Cdn\$/PSU
Balance at December 31, 2016	—	—
Granted	103,500	0.01
Balance, September 30, 2017	103,500	0.01

The fair value of each PSU granted is based on the share price at which the common shares of the Company traded for on the grant date. The weighted average fair value at the grant date for the nine months ended September 30, 2017 was Cdn\$16.01 per PSU.



d) Equity settled share-based compensation

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Option expense	\$ 1,772	\$ 1,493	\$ 5,602	\$ 4,159
Restricted and performance share units expense	3,094	1,687	9,035	4,852
Total	\$ 4,866	\$ 3,180	\$ 14,637	\$ 9,011

13. Cash Settled Incentive Plans

a) Share appreciation rights ("SARs")

Parex Colombia has a SARs plan that provides for the issuance of SARs to certain employees of Parex Colombia. The plan entitles the holders to receive a cash payment equal to the excess of the market price of the Company's common shares at the time of exercise over the grant price. At any time, if the current market price of the Company's common shares exceeds four times the grant price, Parex has the option to require the holders to exercise all vested SARs. SARs typically vest over a three-year period and expire five years from the date of grant. The SARs liability cannot be settled by the issuance of common shares.

	Number of SARs	Weighted average exercise price Cdn\$/SAR
Balance, December 31, 2015	3,475,001	9.03
Granted	1,574,468	15.55
Exercised	(961,233)	7.72
Forfeited	(281,999)	10.26
Balance, December 31, 2016	3,806,237	11.91
Granted	134,086	16.39
Exercised	(502,277)	8.12
Forfeited	(165,691)	11.56
Balance, September 30, 2017	3,272,355	12.70

As at September 30, 2017, 792,012 SARs were vested (December 31, 2016 - 1,077,450).

Obligations for payments of cash under the SARs plan are accrued as compensation expense over the vesting period based on the fair value of SARs, subject to appreciation limits specified in the plan. The fair value of SARs is measured using the Black-Scholes pricing model at each reporting date based on weighted average pricing assumptions noted below:

For the nine months ended September 30,	2017	2016
Risk-free interest rate (%)	1.69	0.54
Expected life (years)	4.4	4.0
Expected volatility (%)	43	47
Share price (\$/Cdn)	15.05	16.65
Expected dividends	—	—

As at September 30, 2017, the total SARs liability accrued is \$12.1 million (December 31, 2016 - \$13.5 million) of which \$2.8 million (December 31, 2016 - \$1.7 million) is classified as long-term in accordance with the three year vesting period. The intrinsic value of SARs at September 30, 2017 was \$8.9 million (December 31, 2016 - \$9.3 million).

b) Deferred share units ("DSUs")

The Company has in place a deferred share unit plan pursuant to which the Company may grant deferred shares to all non-employee directors. The deferred share units vest immediately and are settled in cash upon the retirement of the non-employee director from the Parex Board. The value of the DSUs at the exercise date is equivalent to the five day weighted average share price at which the common shares of the Company traded for immediately preceding the exercise date. DSUs can only be redeemed following departure from the Company in accordance with the terms of the DSU Plan. The DSUs liability cannot be settled by the issuance of common shares.



	Number of DSU's	Weighted average exercise price Cdn\$/DSU
Balance, December 31, 2015	78,600	—
Granted	67,300	—
Balance at December 31, 2016	145,900	—
Granted	65,075	—
Exercised	(17,000)	—
Balance, September 30, 2017	193,975	—

The fair value at the grant date is equivalent to the five day weighted average share price at which the common shares of the Company traded for immediately preceding the grant date. The weighted average fair value at the grant date for the nine months ended September 30, 2017 was Cdn\$16.67 per DSU (year ended December 31, 2016 - Cdn\$16.82 per DSU).

Given the DSUs vest immediately, obligations for payments of cash under the DSUs plan are accrued as compensation expense immediately based on the fair value of the DSU. As at September 30, 2017, the total DSUs liability accrued is \$2.3 million (December 31, 2016 - \$nil) of which \$2.1 million (December 31, 2016 - \$nil) is classified as long-term in accordance with the terms of the DSU plan.

c) Cash settled restricted share units ("CRSUs")

Parex Colombia has a CRSUs plan that provides for the issuance of CRSUs to certain employees of Parex Colombia. The plan entitles the holders to receive a cash payment equal to the market price of the Company's common shares at the time of exercise. CRSUs vest over a three-year period and are exercised at the vest date. The CRSUs liability cannot be settled by the issuance of common shares.

	Number of CRSUs	Weighted average exercise price Cdn\$/CRSU
Balance, December 31, 2016	—	—
Granted	474,470	—
Balance, September 30, 2017	474,470	—

As at September 30, 2017, no CRSUs were vested.

Obligations for payments of cash under the CRSUs plan are accrued as compensation expense over the vesting period based on the fair value of CRSUs. The fair value of CRSUs is equivalent to the trading value of a common share of the Company on the valuation date. As at September 30, 2017, the total CRSUs liability accrued is \$1.0 million (December 31, 2016 - \$nil) of which \$0.4 million (December 31, 2016 - \$nil) is classified as long-term in accordance with the three year vesting period. For the nine months ended September 30, 2017, Parex recorded \$1.0 million of compensation costs related to the outstanding CRSUs (year ended December 31, 2016 - \$nil).

d) Cash settled share-based compensation

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
SARs expense	\$ 1,786	\$ 6,580	\$ 1,645	\$ 11,526
DSUs expense	296	—	1,161	—
CRSUs expense	880	—	957	—
Total	\$ 2,962	\$ 6,580	\$ 3,763	\$ 11,526

14. Income Tax

The components of tax expense for the three and nine months ended September 30, 2017 and 2016 were as follows:

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Current tax expense	\$ 16,166	\$ 1,951	\$ 28,528	\$ 1,657
Deferred tax expense (recovery)	(29,929)	1,002	(11,589)	(20,132)
Tax expense (recovery)	\$ (13,763)	\$ 2,953	\$ 16,939	\$ (18,475)



Effective July 1, 2017 the Company entered into an intercompany purchase/sale agreement between two of its subsidiaries, whereby certain assets were effectively sold and their respective working interests were consolidated into one subsidiary. The purpose of the transaction was to make the Company's tax structure more efficient for future years. The impact of this restructuring is that the company incurred recapture and capital gains taxes in 2017 however has gained increased tax basis in the consolidated entity.

The completion of the tax restructuring impacted current tax in the quarter by approximately \$6.0 million. The deferred tax recovery in the third quarter of \$29.9 million is mainly a result of the voluntary tax restructuring transaction.

15. Net Income (Loss) per Share

a) Basic net income (loss) per share

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Net income (loss)				
Net income (loss) for the purpose of basic net income (loss) per share	\$ 55,527	\$ 6,811	\$ 99,157	\$ (1,004)
Weighted average number of shares for the purposes of basic net income (loss) per share (000s)	154,472	152,700	154,006	151,985
Basic net income (loss) per share	\$ 0.36	\$ 0.04	\$ 0.64	\$ (0.01)

b) Diluted net income (loss) per share

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Net income (loss)				
Net income (loss) used to calculate diluted net income (loss) per share	\$ 55,527	\$ 6,811	\$ 99,157	\$ (1,004)
Weighted average number of shares for the purposes of basic net income (loss) per share (000s)	154,472	152,700	154,006	151,985
Dilutive effect of stock options, RSUs and PSUs on potential common shares	3,463	3,308	3,838	—
Weighted average number of shares for the purposes of diluted net income (loss) per share	157,935	156,008	157,844	151,985
Diluted net income (loss) per share	\$ 0.35	\$ 0.04	\$ 0.63	\$ (0.01)

For the three and nine months ended September 30, 2017, 1,924,850 stock options (three months ended September 30, 2016 - 9,375 stock options) were excluded from the diluted weighted average shares calculation as they were anti-dilutive. The Company reported a net loss for the nine months ended September 30, 2016 and therefore all stock options and RSUs that were otherwise dilutive were anti dilutive and excluded from the diluted earnings per share.



16. Supplemental Disclosure of Cash Flow Information

a) Net change in non-cash working capital

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Accounts receivable	\$ (5,701)	\$ 979	\$ (23,139)	\$ 3,440
Prepays and other current assets	(370)	1,526	(824)	6,211
Oil inventory	(788)	290	762	3,207
Accounts payable and accrued liabilities	(15,424)	14,486	24,861	(26,910)
Depletion related to oil inventory	231	(103)	(178)	(1,498)
Net change in non-cash working capital	\$ (22,052)	\$ 17,178	\$ 1,482	\$ (15,550)
Operating	(15,561)	10,162	(2,055)	(21,538)
Investing	(6,491)	7,016	3,537	5,988
Financing	—	—	—	—
Net change in non-cash working capital	\$ (22,052)	\$ 17,178	\$ 1,482	\$ (15,550)

b) Interest and taxes paid

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Cash interest paid	\$ 6	\$ 129	\$ 32	\$ 364
Cash income and equity taxes paid	\$ 447	\$ —	\$ 2,627	\$ 18,291

17. Capital Management

The Company's strategy is to maintain a strong capital base in order to provide flexibility in the future development of the business and maintain the confidence of investors and capital markets.

The Company manages its capital to achieve the following:

- Maintain balance sheet strength in order to meet the Company's strategic growth objectives; and
- Ensure financial capacity is available to fund the Company's exploration commitments.

Parex has a senior secured credit facility which as at September 30, 2017 had a borrowing base in the amount of \$100.0 million (December 31, 2016 - \$175.0 million). The credit facility was voluntarily reduced from \$175.0 million to \$100.0 million in May 2017 to reduce costs associated with the credit facility. The credit facility is intended to serve as means to increase liquidity and fund cash needs as they arise. As at September 30, 2017, \$nil (December 31, 2016 - \$nil) was drawn on the credit facility.

The Company has also provided a general security agreement to Export Development Canada ("EDC") in connection with the performance security guarantees that support letters of credit provided to the Colombian National Hydrocarbon Agency ("ANH") and Empresa Colombiana de Petroleos S.A. ("Ecopetrol") related to the exploration work commitments on its Colombian concessions (see note 20 - Commitments). This performance guarantee facility has a limit of \$250.0 million (December 31, 2016 - limit of \$200.0 million) of which \$116.6 million (December 31, 2016 - \$126.4 million) is utilized at September 30, 2017. At September 30, 2017, there is an additional \$25.0 million (December 31, 2016 - \$21.3 million) of letters of credit that are provided by a Latin American bank on an unsecured basis.

As at September 30, 2017, the Company's net working capital surplus was \$140.3 million (December 31, 2016 - \$93.3 million), of which \$195.9 million is cash.

Parex has the ability to adjust its capital structure by issuing new equity or debt and making adjustments to its capital expenditure program to the extent the capital expenditures are not committed. The Company considers its capital structure at this time to include shareholders' equity and the credit facility. As at September 30, 2017 shareholders' equity was \$832.2 million (December 31, 2016 - \$713.8 million).



18. Financial Instruments and Risk Management

The Company's non-derivative financial instruments recognized on the consolidated balance sheet consist of cash, accounts receivable, accounts payable and accrued liabilities. Non-derivative financial instruments are recognized initially at fair value. The fair values of the current financial instruments approximate their carrying value due to their short-term maturity. The fair value of the revolving credit facility is equal to its carrying amount as the facility bears interest at floating rates and the credit spreads within the facility are indicative of market rates.

a) Credit risk

Credit risk is the risk of loss associated with the inability of a third party to fulfill its payment obligations. The Company is exposed to the risk that third parties that owe it money do not meet their obligations. The Company assesses the financial strength of its joint venture partners and oil marketing counterparties in its management of credit exposure.

The Company for the nine months ended September 30, 2017 had the majority of its oil sales to 10 counterparties. Accounts receivable balance as at September 30, 2017 are substantially made up of receivables with customers in the oil and gas industry and are subject to normal industry credit risks. The Company historically has not experienced any collection issues with its crude oil customers. At September 30, 2017, there are \$1.5 million of accounts receivable past due, all of which are considered collectible (December 31, 2016 - \$0.6 million).

b) Liquidity risk

The Company's approach to managing liquidity risk is to have sufficient cash and/or credit facilities to meet its obligations when due. Management typically forecasts cash flows for a period of 12 to 36 months to identify any financing requirements. Liquidity is managed through daily and longer-term cash, debt and equity management strategies. These include estimating future cash generated from operations based on reasonable production and pricing assumptions, estimating future discretionary and non-discretionary capital expenditures and assessing the amount of equity or debt financing available. The Company is committed to maintaining a strong balance sheet and has the ability to change its capital program based on expected operating cash flows. The balance drawn on the Company's \$100.0 million credit facility at September 30, 2017 was \$nil.

The following are the contractual maturities of financial liabilities at September 30, 2017:

	Less than 1 year	2-3 Years	4-5 Years	Thereafter	Total
Accounts payable and accrued liabilities	\$ 81,141	—	—	—	\$ 81,141
Cash settled equity plans payable	10,133	5,274	—	—	15,407
Total	\$ 91,274	5,274	—	—	\$ 96,548

⁽¹⁾ Includes the liability for derivative financial instruments.

The following are the contractual maturities of financial liabilities at December 31, 2016:

	Less than 1 year	2-3 Years	4-5 Years	Thereafter	Total
Accounts payable and accrued liabilities ⁽¹⁾	\$ 76,199	—	—	—	\$ 76,199
SARs payable	11,818	1,652	—	—	13,470
Total	\$ 88,017	1,652	—	—	\$ 89,669

⁽¹⁾ Includes the liability for derivative financial instruments.

c) Commodity price risk

The Company is exposed to commodity price movements as part of its operations, particularly in relation to the prices received for its oil production. Crude oil is sensitive to numerous worldwide factors, many of which are beyond the Company's control. Changes in global supply and demand fundamentals in the crude oil market and geopolitical events can significantly affect crude oil prices. Consequently, these changes could also affect the value of the Company's properties, the level of spending for exploration and development and the ability to meet obligations as they come due. The Company's oil production is sold under short-term contracts, exposing it to the risk of near-term price movements.

As at September 30, 2017, the Company had outstanding risk management contracts which are used to manage its exposure to fluctuations in the price of crude oil.



The following is a summary of the ICE Brent priced crude oil risk management contracts in place during the nine months ended September 30, 2017:

Period Hedged	Reference	Volume bbls/d	Sold Put	Purchased Put	Sold Call	Premium
January 1, 2017 to February 28, 2017	ICE Brent	5,000	\$ 44.00	\$ 48.00	\$ 63.35	\$ —
January 1, 2017 to March 31, 2017	ICE Brent	5,000	\$ 40.00	\$ 45.00	\$ 59.40	\$ —
April 1, 2017 to June 30, 2017	ICE Brent	5,000	\$ 40.00	\$ 45.00	\$ 64.00	\$ —
April 1, 2017 to September 30, 2017	ICE Brent	5,000	\$ 40.00	\$ 50.00	\$ —	\$ 1.30
July 1, 2017 to September 30, 2017	ICE Brent	5,000	\$ 45.00	\$ 50.00	\$ —	\$ 0.95
October 1, 2017 to December 31, 2017	ICE Brent	5,000	\$ 40.00	\$ 45.00	\$ 61.75	\$ —
January 1, 2018 to March 31, 2018	ICE Brent	5,000	\$ 45.00	\$ 48.00	\$ —	\$ 0.53

The fair value of the ICE Brent priced crude oil risk management contracts at September 30, 2017 was a \$0.3 million liability (December 31, 2016 – liability of \$1.7 million) and is recorded in the financial statement line item “Derivative financial instruments” in the consolidated balance sheet.

The table below summarizes the (gain) loss on the commodity risk management contracts:

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Realized (gain) on commodity risk management contracts	\$ (263)	\$ (319)	\$ (624)	\$ (949)
Premiums paid on commodity risk management contracts	438	1,212	1,627	6,528
Unrealized (gain) loss on commodity risk management contracts	2,120	(3,743)	(1,117)	3,702
Total	\$ 2,295	\$ (2,850)	\$ (114)	\$ 9,281

As shown in the table above, as at September 30, 2017, Parex had committed to the future sale of 460,000 barrels of oil with puts and calls from Brent oil prices of \$40.00 to \$61.75 per bbl. The following sensitivity shows the resulting unrealized loss (gain) and impact on (loss) income before tax for the oil hedged contracts if Brent oil price were to increase/decrease by \$10/bbl from the spot rate as at September 30, 2017:

Oil hedged contract loss (gain)	Brent Price	Impact for the nine months ended September 30, 2017	
		Increase of \$10/bbl	Decrease of \$10/bbl
Period end	\$	2,610	\$ (961)

Subsequent to September 30, 2017, Parex entered into the following ICE Brent priced crude oil risk management contracts:

Period Hedged	Reference	Volume bbls/d	Sold Put	Purchased Put	Sold Call	Premium
January 1, 2018 to March 31, 2018	ICE Brent	5,000	\$ 47.00	\$ 50.00	\$ —	\$ 0.40
January 1, 2018 to March 31, 2018	ICE Brent	5,000	\$ 47.00	\$ 50.00	\$ —	\$ 0.25



19. Segmented Information

The Company has foreign subsidiaries and the following segmented information is provided:

For the three months ended September 30, 2017 (unaudited)	Canada	Colombia	Total
Oil and natural gas sales	\$ —	\$ 159,929	\$ 159,929
Royalties	—	(13,015)	(13,015)
Revenue	—	146,914	146,914
Commodity risk management contracts gain	—	(2,295)	(2,295)
	—	144,619	144,619
Expenses			
Production	—	18,191	18,191
Transportation	—	35,678	35,678
Purchased oil	—	942	942
General and administrative	2,959	5,984	8,943
Equity settled share-based compensation	4,866	—	4,866
Cash settled share-based compensation	297	2,665	2,962
Depletion, depreciation and amortization	46	28,709	28,755
Foreign exchange loss	21	1,128	1,149
	8,189	93,297	101,486
Finance (income)	(191)	(433)	(624)
Finance expense	258	1,735	1,993
Net finance expense	67	1,302	1,369
Income (loss) before taxes	\$ (8,256)	\$ 50,020	\$ 41,764
Current tax expense	—	16,166	16,166
Deferred tax (recovery)	—	(29,929)	(29,929)
Net income (loss)	\$ (8,256)	\$ 63,783	\$ 55,527
Capital assets (end of period)	\$ 275	\$ 692,450	\$ 692,725
Capital expenditures	\$ 4	\$ 51,430	\$ 51,434
Total assets (end of period)	\$ 76,139	\$ 981,720	\$ 1,057,859
For the three months ended September 30, 2016 (unaudited)	Canada	Colombia	Total
Oil and natural gas sales	\$ —	\$ 127,541	\$ 127,541
Royalties	—	(8,927)	(8,927)
Revenue	—	118,614	118,614
Commodity risk management contracts	—	2,850	2,850
	—	121,464	121,464
Expenses			
Production	—	12,341	12,341
Transportation	—	32,843	32,843
Purchased oil	—	16,569	16,569
General and administrative	4,136	2,623	6,759
Equity settled share-based compensation	3,180	—	3,180
Cash settled share-based compensation	—	6,580	6,580
Depletion, depreciation and amortization	78	31,839	31,917
Foreign exchange (gain) loss	1,002	(826)	176
	8,396	101,969	110,365
Finance (income)	(137)	56	(81)
Finance expense	307	1,109	1,416
Net finance expense	170	1,165	1,335
Net income (loss) before taxes	\$ (8,566)	\$ 18,330	\$ 9,764
Current tax expense	—	1,951	1,951
Deferred tax expense	—	1,002	1,002
Net income (loss)	\$ (8,566)	\$ 15,377	\$ 6,811
Capital assets (end of period)	\$ 440	\$ 651,539	\$ 651,979
Capital expenditures	\$ 33	\$ 26,280	\$ 26,313
Total assets (end of period)	\$ 82,559	\$ 864,795	\$ 947,354

For the nine months ended September 30, 2017 (unaudited)	Canada	Colombia	Total
Oil and natural gas sales	\$ —	\$ 455,477	\$ 455,477
Royalties	—	(38,688)	(38,688)
Revenue	—	416,789	416,789
Commodity risk management contracts gain	—	114	114
	—	416,903	416,903
Expenses			
Production	—	49,943	49,943
Transportation	—	103,781	103,781
Purchased oil	—	4,228	4,228
General and administrative	8,350	16,732	25,082
Legal settlement	15,000	—	15,000
Equity settled share-based compensation	14,637	—	14,637
Cash settled share-based compensation	1,161	2,602	3,763
Depletion, depreciation and amortization	138	78,932	79,070
Foreign exchange loss	47	159	206
	39,333	256,377	295,710
Finance (income)	(509)	(991)	(1,500)
Finance expense	1,073	5,524	6,597
Net finance expense	564	4,533	5,097
Income (loss) before taxes	(39,897)	155,993	116,096
Current tax expense	—	28,528	28,528
Deferred tax (recovery)	—	(11,589)	(11,589)
Net income (loss)	\$ (39,897)	\$ 139,054	\$ 99,157
Capital assets (end of period)	\$ 275	\$ 692,450	\$ 692,725
Capital expenditures	\$ 28	\$ 145,977	\$ 146,005
Total assets (end of period)	\$ 76,139	\$ 981,720	\$ 1,057,859
For the nine months ended September 30, 2016 (unaudited)	Canada	Colombia	Total
Oil and natural gas sales	\$ —	\$ 313,630	\$ 313,630
Royalties	—	(23,967)	(23,967)
Revenue	—	289,663	289,663
Commodity risk management contracts	—	(9,281)	(9,281)
	—	280,382	280,382
Expenses			
Production	—	37,886	37,886
Transportation	—	99,442	99,442
Purchased oil	—	20,939	20,939
General and administrative	11,017	12,836	23,853
Equity settled share-based compensation	9,011	—	9,011
Cash settled share-based compensation	—	11,526	11,526
Depletion, depreciation and amortization	231	92,413	92,644
Foreign exchange (gain) loss	28	(312)	(284)
	20,287	274,730	295,017
Finance (income)	(404)	(558)	(962)
Finance expense	1,195	4,611	5,806
Net finance expense	791	4,053	4,844
Net income (loss) before taxes	(21,078)	1,599	(19,479)
Current tax expense	—	1,657	1,657
Deferred tax (recovery)	—	(20,132)	(20,132)
Net income (loss)	(21,078)	20,074	(1,004)
Capital assets (end of period)	\$ 440	\$ 651,539	\$ 651,979
Capital expenditures	\$ 126	\$ 44,616	\$ 44,742
Total assets (end of period)	\$ 82,559	\$ 864,795	\$ 947,354

In Colombia the majority of oil sales are with ten customers in the oil and gas industry and are subject to normal industry credit risks.



20. Commitments

a) Colombia

At September 30, 2017, performance guarantees are in place with Ecopetrol for the Capachos and Aguas Blancas farm-in blocks and with the ANH for all other blocks. The guarantees are in the form of issued letters of credit totaling \$141.7 million (December 31, 2016 - \$148.7 million) to support the exploration work commitments in respect of the 22 blocks in Colombia.

At September 30, 2017, EDC has provided the Company's bank with performance security guarantees to support approximately \$116.6 million (December 31, 2016 - \$126.4 million) of the letters of credit issued on behalf of Parex. The EDC guarantees have been secured by a general security agreement issued by Parex in favour of EDC. The letters of credit issued to the ANH and Ecopetrol are reduced from time to time to reflect completed work on an ongoing basis.

The value of the Company's exploration commitments as at September 30, 2017 in respect of the Colombia blocks are estimated to be as follows:

2017	\$	1,200
2018		129,981
Thereafter		21,000
	\$	152,181

b) Operating leases

In the normal course of business, Parex has entered into arrangements and incurred obligations that will impact the Company's future operations and liquidity. These commitments include leases for office space and accommodations. The existing minimum lease payments for office space and accommodations at September 30, 2017 are as follows:

	Total	2017	2018	2019	2020	2021	Thereafter
Office and accommodations	\$ 7,818	571	1,401	1,006	1,302	1,023	2,515

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of Parex Resources Inc. ("Parex" or "the Company") for the period ended September 30, 2017 is dated November 7, 2017 and should be read in conjunction with the Company's unaudited condensed interim consolidated financial statements for the period ended September 30, 2017, as well as the Company's audited consolidated annual financial statements for the year ended December 31, 2016. The unaudited condensed interim consolidated financial statements and the audited consolidated annual financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board.

Additional information related to Parex and factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities, including the Company's Annual Information Form dated March 21, 2017 ("AIF"), and may be accessed through the SEDAR website at www.sedar.com.

All financial amounts are in United States (US) dollars unless otherwise stated.

Company Profile

Parex is an oil and gas company actively engaged in crude oil exploration, development and production in Colombia. Headquartered in Calgary, Canada, Parex, through its foreign subsidiaries, holds interests in onshore exploration and production blocks totaling approximately 1,698,931 gross acres. The common shares of the Company trade on the Toronto Stock Exchange ("TSX") under the symbol PXT.

Abbreviations

Refer to the end of the MD&A for commonly used abbreviations in the document. Refer to page 17 for the Advisory on Forward-Looking Statements and page 19 for Non-GAAP Terms used.

Three months ended September 30, 2017 ("third quarter or Q3") Highlights

- Quarterly production was 36,195 boe/d (99% crude oil), representing an increase of 6 percent over the previous quarter ended June 30, 2017 and an increase of 22 percent over the prior year comparative period;
- Funds flow from operations was \$66.0 million (\$0.43 per share basic) as compared to \$0.30 per share for the prior year comparative period and \$0.34 per share in the previous quarter ended June 30, 2017. Funds flow was impacted by approximately \$6.0 million (\$0.04 per share basic) due to a voluntary tax restructuring in the quarter;
- Earned net income of \$55.5 million (\$0.36 per share basic) compared to net income of \$6.8 million (\$0.04 basic per share) in the comparative quarter of 2016. For the first nine months of 2017 Parex has earned \$99.2 million of net income;
- Realized a sales price of \$48.07/boe during the period at a \$4.10/bbl discount to the average Brent price, and an operating netback of \$27.90/boe. The differential to Brent decreased from the historical range of \$6-\$7/bbl;
- For the nine months ended September 30, 2017 the Company recognized free funds flow of \$39.7 million while increasing production by approximately 16 percent;
- Capital expenditures were \$51.4 million in the period compared to \$26.3 million in the comparative period of 2016. 2017 year to date capital expenditures were \$146.0 million. Parex expects to invest approximately \$220 million in capital projects in 2017;
- Working capital was \$140.3 million at September 30, 2017 compared to \$128.3 million at June 30, 2017 and \$117.7 million at September 30, 2016. The Company has an undrawn syndicated bank credit facility of \$100.0 million; and
- Participated in drilling 7 wells in Colombia resulting in 6 oil wells and 1 under test, for a success rate of 100 percent.

Financial Summary

(Financial figures in 000s except per share amounts)	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Average daily production (bopd)	35,886	29,501	34,085	29,146
Average daily natural gas production (mcf/d)	1,854	1,518	1,722	1,362
Average oil and natural gas production (boe/d)	36,195	29,754	34,372	29,373
Production split (% crude oil)	99	99	99	99
Average realized sales price (\$/boe)	48.07	40.19	47.88	35.59
Operating netback (\$/boe) ⁽¹⁾	27.90	20.87	27.55	16.27
Oil and natural gas sales	159,929	127,541	455,477	313,630
Funds flow provided by operations	65,998	45,091	185,667	92,340
Per share – basic	0.43	0.30	1.21	0.61
Per share – diluted ⁽¹⁾	0.42	0.29	1.18	0.60
Net income (loss)	55,527	6,811	99,157	(1,004)
Per share – basic	0.36	0.04	0.64	(0.01)
Per share – diluted	0.35	0.04	0.63	(0.01)
Capital Expenditures	51,434	26,313	146,005	44,742
Total assets (end of period)	1,057,859	947,354	1,057,859	947,354
Working capital surplus (end of period) ⁽²⁾	140,292	117,747	140,292	117,747
Bank debt (end of period) ⁽³⁾	—	—	—	—
Weighted average shares outstanding (000s)				
Basic	154,472	152,700	154,006	151,985
Diluted	157,935	156,008	157,844	155,139
Outstanding shares (end of period (000s))	154,556	152,666	154,556	152,666

⁽¹⁾ Non-GAAP term. See "Non-GAAP Terms".

⁽²⁾ Working capital calculation does not take into consideration the undrawn amount available under the syndicated bank credit facility ("credit facility").

⁽³⁾ Syndicated bank credit facility borrowing base of \$100.0 million as at September 30, 2017, voluntarily reduced from the borrowing base of \$175.0 million at September 30, 2016.

Strategy

The Company's strategy is to leverage South American and Western Canadian experience and capability to create shareholder value. Jurisdictions will be targeted that have stable fiscal regimes coupled with oil-prone hydrocarbon-rich basins in under-explored areas. Parex will apply proven technology used in the Western Canada Sedimentary Basin in basins with large oil-in-place potential. The Company will focus on short cycle time from discovery to bringing new reserves on-stream and use a portfolio approach to manage subsurface and commercial risks.



Principal Properties

As at September 30, 2017 the Company's principal land holdings and interests in exploration and production blocks held by its subsidiaries were as follows:

	Working Interest	Gross Acres	Net Acres
Colombia Llanos Basin			
<i>Operated Properties</i>			
LLA-16, 20, 29 and 30	100 %	201,864	201,864
Los Ocarros	100 %	31,066	31,066
El Eden	100 %	6,397	6,397
Cabrestero	100 %	29,562	29,562
LLA-40	100 %	83,465	83,465
LLA-26	100 %	184,061	184,061
Capachos ⁽¹⁾	50 %	64,073	32,037
LLA-32	70 %	57,040	39,928
LLA-10	50 %	189,544	94,772
<i>Non-Operated Properties</i>			
LLA-34	55 %	68,382	37,610
Balay	10 %	4,500	450
Colombia Magdalena Basin			
<i>Operated Properties</i>			
VMM-11	100 %	116,826	116,826
Morpho	100 %	51,420	51,420
VIM-1	100 %	223,651	223,651
VMM-9	100 %	152,412	152,412
Aguas Blancas ⁽¹⁾	50 %	13,386	6,693
De Mares ⁽¹⁾	50 %	174,387	87,194
Playon ⁽¹⁾	50 %	43,200	21,600
Sogamoso	100 %	3,695	3,695
Total		1,698,931	1,404,703

(1) Lands are subject to farm-in-agreement earning terms and/or regulatory approval.

Exploration properties that are deemed non-commercial will be relinquished in due course. Accordingly, the gross and net acres described above may decrease over time as lands deemed non-commercial are relinquished. For a description of blocks phase, commitments and letters of credit refer to the Company's AIF.

2017 Guidance

Q4 2017 production to expected to average 38,500 boe/d, generating over 23% increase from the Q4 2016 average production rate and the full year 2017 average production is anticipated to be above 35,000 boe/d. Previous 2017 full year average production guidance was to range between 34,000 to 36,000 boe/d. Q1 2018 production is expected to average above 40,000 boe/d. The full year 2017 capital expenditures forecast is approximately \$220 million. Parex still anticipates fully funding its capital program with funds flow from operations.



Financial and Operational Results

Consolidated Results of Operations

Parex' operations are conducted in Colombia and Canada which are the Company's reportable segments.

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Average daily production				
Colombia – oil (bbl/d)	35,886	29,501	34,085	29,146
Colombia – natural gas (mcf/d)	1,854	1,518	1,722	1,362
Total (boe/d)	36,195	29,754	34,372	29,373
Production split (% crude oil production)	99	99	99	99
Average daily sales of oil and natural gas				
Colombia – produced oil (bbl/d)	35,596	29,601	34,164	29,645
Colombia – purchased oil (bbl/d)	259	986	396	1,179
Colombia - Ocesa overlift (bbl/d)	—	3,650	—	1,230
Colombia – produced natural gas (Mcf/d)	1,854	1,518	1,722	1,362
Total (boe/d)	36,164	34,490	34,847	32,281
Operating netback (\$'000s) ⁽¹⁾				
Oil and natural gas sales	\$ 159,929	\$ 127,541	\$ 455,477	\$ 313,630
Royalties	(13,015)	(8,927)	(38,688)	(23,967)
Net revenue	146,914	118,614	416,789	289,663
Production expense	(18,191)	(12,341)	(49,943)	(37,886)
Transportation expense	(35,678)	(32,843)	(103,781)	(99,442)
Purchased oil	(942)	(16,569)	(4,228)	(20,939)
Operating netback	\$ 92,103	\$ 56,861	\$ 258,837	\$ 131,396
Operating netback (per boe) ⁽¹⁾				
Oil and natural gas sales	\$ 48.07	\$ 40.19	\$ 47.88	\$ 35.59
Royalties	(3.94)	(3.25)	(4.11)	(2.94)
Net revenue	44.13	36.94	43.77	32.65
Production expense	(5.51)	(4.49)	(5.31)	(4.65)
Transportation expense	(10.72)	(11.58)	(10.91)	(11.73)
Operating netback	\$ 27.90	\$ 20.87	\$ 27.55	\$ 16.27

⁽¹⁾ Refer to page 19 "Non-GAAP Terms" for a description and details of the operating netback calculation.

The average realized sales price in Colombia for the three and nine months ended September 30, 2017 was \$48.07/boe and \$47.88/boe in comparison to \$40.19/boe and \$35.59/boe in the comparative prior year periods. The average realized sales price was \$46.84/boe for the second quarter of 2017.

Royalty charges for the three and nine months ended September 30, 2017 were \$3.94/boe and \$4.11/boe in comparison to \$3.25/boe and \$2.94/boe in the comparative prior year periods. Royalty charges in the second quarter of 2017 were \$4.03/boe.

Production expense for the three and nine months ended September 30, 2017 was \$5.51/boe and \$5.31/boe compared to \$4.49/boe and \$4.65/boe in the comparative prior year periods. Production expense for the second quarter of 2017 was \$5.31/boe.

Transportation expense for the three and nine months ended September 30, 2017 was \$10.72/boe and \$10.91/boe compared to \$11.58/boe and \$11.73/boe in the comparative prior year periods. Transportation expense in the second quarter of 2017 was \$10.91/boe.

Overall, the Company's benchmark Brent price increased by \$1.30/bbl in the third quarter as compared to the second quarter of 2017, which is in line with the operating netback increase of \$1.31/boe.



Colombian Oil and Natural Gas Sales

a) Average Daily Production and Sales Volumes (boe/d)

	For the three months ended Sept 30,		For the nine months ended Sept 30,	
	2017	2016	2017	2016
Block LLA-34 (Tigana, Jacana, Tua, Tarotaro, and Tilo fields)	25,973	17,937	24,244	17,486
Block Cabrestero (Bacano, Akira and Kitara fields)	4,517	3,215	3,537	2,865
Block LLA-26 (Rumba field)	2,622	4,662	3,385	4,513
Block LLA-32 (Kananaskis, Calona, and Carmentea fields)	905	1,448	959	1,486
Block LLA-40 (Begonia field)	600	475	436	625
Block Los Ocarros (Las Maracas field)	802	791	954	880
Other	467	973	570	1,291
Total Crude Oil Production	35,886	29,501	34,085	29,146
Natural gas production	309	253	287	227
Total crude oil and natural gas production	36,195	29,754	34,372	29,373
Crude oil inventory (build) draw	(290)	3,750	79	1,729
Average daily sales of produced oil and natural gas	35,905	33,504	34,451	31,102
Purchased oil	259	986	396	1,179
Sales Volumes	36,164	34,490	34,847	32,281

Oil and natural gas production for the third quarter of 2017 averaged 36,195 boe/d, an increase of approximately 22 percent from the third quarter of 2016. The increase in oil and natural gas sales in the third quarter of 2017 to 36,164 boe/d compared to the reported Colombian oil sales of 34,490 boe/d for the three months ended September 30, 2016 was primarily a result of the increase in oil production in 2017.

b) Average Crude Oil Reference and Realized Prices

	For the three months ended Sept 30,		For the nine months ended Sept 30,	
	2017	2016	2017	2016
Reference Prices				
Brent (\$/bbl)	52.17	46.98	52.55	43.15
Vasconia (\$/bbl)	49.15	41.92	48.61	37.46
WTI (\$/bbl)	48.13	44.91	49.37	41.56
Average Realized Prices				
Realized sales price (\$/bbl)	48.07	40.22	47.88	35.57
Realized oil hedging gain (loss) (\$/bbl)	(0.05)	(0.28)	(0.11)	(0.64)
Realized price after hedging (\$/bbl)	48.02	39.94	47.77	34.93
Realized price differential to Brent crude (\$/bbl)	(4.10)	(6.76)	(4.67)	(7.58)

The differential between Brent reference pricing and the realized crude oil sale price in the third quarter of 2017 was \$4.10/bbl. The differential for last two quarters in succession is a substantial improvement over historical averages of \$6-\$7/bbl (see below). The main driver of this reduction in differential is related to decrease in Vasconia crude oil supply in Colombia, coupled with greater demand for heavy oil blends at US Gulf coast refineries. Differences between the Parex realized price and the Vasconia average is mainly a result of quality adjustments on certain oil sale contracts and timing of oil sales.



In the table below, the quarter over quarter Brent and Vasconia crude differentials are shown:

Average price for the period	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016
Brent (\$/bbl)	52.17	50.87	54.61	51.13	46.98
Vasconia (\$/bbl)	49.15	47.10	49.57	46.17	41.92
Parex realized sales price (\$/bbl)	48.07	46.84	48.72	44.84	40.22
Parex realized price (differential) to Brent crude (\$/bbl)	(4.10)	(4.03)	(5.89)	(6.29)	(6.76)
Parex realized price (differential) to Vasconia crude (\$/bbl)	(1.08)	(0.26)	(0.85)	(1.33)	(1.70)

c) Natural Gas Revenue and Realized Prices

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Revenue (000's)	\$ 1,172	\$ 862	\$ 3,190	\$ 2,378
Realized sales price (\$/Mcf)	6.95	6.17	6.79	6.39

d) Oil and Natural Gas Revenue

Third quarter 2017 oil revenue increased \$32.4 million or 25 percent as reconciled in the table below to the third quarter of 2016:

(\$000s)		
Oil and natural gas revenue, three months ended September 30, 2016	\$	127,541
Sales volume of produced oil an increase of 7% (2,401 bopd)		8,884
Sales volume of purchased oil, a decrease of 74% (727 bopd)		(2,690)
Oil sales price increase of 20%		26,194
Oil and natural gas revenue, three months ended September 30, 2017	\$	159,929

Oil and natural gas revenue increased in the three months ended September 30, 2017 compared to the same period in 2016 mainly due to the increase in world oil prices and increased sales volumes of produced oil.

e) Colombian Crude Oil Inventory in Transit

As at Sept 30, (\$000s)	2017	2016
Crude oil in transit	\$ 2,072	\$ —

As at September 30, 2017, the Company had 70.9 mbbls of crude oil inventory in transit, which was injected into the Colombian pipelines. The inventory was valued based on direct and indirect expenditures (including production costs, certain transportation costs, depletion expense and royalty expense) at approximately \$29/bbl incurred in bringing the crude oil to its existing condition and location.

As at September 30, 2016, the Company had nil mbbls of crude oil inventory in transit. Based on timing of Company oil sale export cargos the Company was overlifted from the Ocesa pipeline by 335.7 mbbls at September 30, 2016. The overlift position was eliminated during the fourth quarter of 2016.

A reconciliation of quarter to quarter crude oil inventory movements is provided below:



For the periods ended (mbbls)	Sept. 30, 2017	June 30, 2017	March 31, 2017	Dec.31, 2016
Crude oil inventory in transit (overlift)- beginning of the period	44.1	3.1	92.3	(335.7)
Oil production	3,301.7	3,095.1	2,908.5	2,830.1
Oil sales	(3,298.8)	(3,079.1)	(3,056.9)	(2,467.7)
Purchased oil	23.9	25.0	59.2	65.6
Crude oil inventory in transit (overlift) - end of the period	70.9	44.1	3.1	92.3
% of period production	2.1	1.4	—	3.3

Crude oil inventory build and draw down from period to period are subject to factors that the Company does not control such as timing of the number of shipments from storage to export.

f) Purchased Oil

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Purchased oil expense (\$000s)	\$ 942	\$ 16,569	\$ 4,228	\$ 20,939

Purchased oil expense for the three and nine months ended September 30, 2017 was \$0.9 million and \$4.2 million compared to \$16.6 million and \$20.9 million for the 2016 three and nine month comparative periods. Transportation costs are incurred by the Company to transport purchased oil to sale delivery points. Included in purchased oil expense for the nine months ended September 30, 2016 was an accrual based upon the fair value of the overlift position with the Ocesa pipeline.

Colombian Royalties

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Royalties (\$000s)	\$ 13,015	\$ 8,927	\$ 38,688	\$ 23,967
Per unit (\$/boe)	3.94	3.25	4.11	2.94
Percentage of sales ⁽¹⁾	8.2%	8.0%	8.6%	8.2%

⁽¹⁾ Calculated based on Company working interest sales volumes excluding purchased oil volumes sold.

In the three and nine months ended September 30, 2017 royalties as a percentage of sales were 8.2% and 8.6% compared to 8.6% during the three months ended June 30, 2017 and 8.0% and 8.2% for the 2016 three and nine month comparative periods.

The increase in royalties as a percentage of sales from the comparative period is a result of the high price share royalty (HPR) being applicable on fields where accumulated production is in excess of 5 million barrels produced. The calculation includes a minimum baseline WTI oil price which in the prior comparative period this minimum was not reached and therefore the HPR was not applicable. In Q3, 2017 the minimum WTI price was reached and the HPR is applicable.

For further information concerning the HPR please refer to the Company's AIF, which may be accessed through the SEDAR website at www.sedar.com.

Colombian Production Expense

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Production expense (000s)	\$ 18,191	\$ 12,341	\$ 49,943	\$ 37,886
Per unit (\$/boe) ⁽¹⁾	5.51	4.49	5.31	4.65

⁽¹⁾ Calculated based on Company working interest sales volumes excluding purchased oil volumes sold.



A breakdown of the production expense on a per boe basis between operated and non-operated fields are provided below:

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Per unit (\$/boe) – based on sales volumes – operated ⁽¹⁾	7.61	5.41	7.78	5.40
Per unit (\$/boe) – based on sales volumes – non-operated ⁽¹⁾	4.61	3.90	4.32	4.13

⁽¹⁾ Calculated based on Company working interest sales volumes excluding purchased oil volumes sold.

Production expense includes the cost of activities in the field to operate wells and facilities, lift to surface, gather, process, treat and store production.

Production expense for the three and nine months ended September 30, 2017 was \$5.51/boe and \$5.31/boe compared to \$4.49/boe and \$4.65/boe in the prior year comparative periods. Production expense for the second quarter of 2017 was \$5.31/boe. Operated properties production expense in the third quarter of 2017 was \$7.61/boe compared to \$7.80/boe for the second quarter of 2017 and non-operated properties production expense in the third quarter of 2017 was \$4.61/boe compared to \$4.42/boe for the second quarter of 2017. The increase in operated production expense for the nine months ended September 30, 2017 is a result of Colombian peso appreciation over the prior periods and decreased fixed cost absorption on operated fields. The increase in non-operated production expense in the three and nine months ended September 30, 2017 is a result of increased workovers and pump changes on Block LLA-34.

Colombian Transportation Expense

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Transportation expense (\$000s)	\$ 35,678	\$ 32,843	\$ 103,781	\$ 99,442
Per unit (\$/boe)	10.72	11.58	10.91	11.73

Transportation expense includes trucking costs incurred to transport production to several offloading stations for sale and in some instances an oil transportation tariff from delivery point to the buyer's facility and pipeline tariffs.

For the three months ended September 30, 2017, the cost of transportation on a per boe basis has decreased to \$10.72/boe from the second quarter of 2017 of \$10.91/boe and decreased from the comparative period in 2016 of \$11.58/boe. This decrease is a result of decreased pipeline access fees and purchasers being aggressive on bidding for Parex oil volumes.

On a year to date basis transportation expense has decreased to \$10.91/boe from \$11.73/boe in the comparative period in 2016. The main reason for this decrease relates to increased available pipeline and take away capacity as total Colombian oil production has decreased over the past year.

The Company expects transportation costs on a per boe basis for the remainder of 2017 to be in line with 2017 year-to-date results with variability depending on the marketing mix, delivery points and the Colombian peso/US\$ exchange rate.

General and Administrative Expense ("G&A")

(000s)	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Gross G&A	\$ 10,477	\$ 7,738	\$ 30,849	\$ 26,858
G&A recoveries	(1,302)	(173)	(520)	(498)
Capitalized G&A	(232)	(806)	(5,247)	(2,507)
Total net G&A	\$ 8,943	\$ 6,759	\$ 25,082	\$ 23,853
Per unit (\$/boe) ⁽¹⁾	2.69	2.47	2.67	2.97

⁽¹⁾ Calculated based on Company working interest production volumes.

Net G&A was \$8.9 million and \$25.1 million for the three and nine months ended September 30, 2017 compared to \$6.8 million and \$23.9 million for the same periods in 2016. Gross G&A was \$10.5 million and \$30.8 million for the three and nine months ended September 30, 2017 (three and nine months ended September 30, 2016 - \$7.7 million and \$26.9 million). For the nine months ended September 30, 2017 on a per boe basis net G&A has decreased 10 percent compared to the comparative period in 2016. The increase in net G&A in the third quarter over the prior year



comparative quarter is mainly a result of the appreciation of the Canadian dollar from the prior period plus other one-time charges in the third quarter of 2017.

The Company's G&A expense is denominated in local currencies of COP and Cdn dollar which if they were to appreciate/depreciate would have an impact on G&A expense. Refer to the foreign exchange sensitivity analysis on page 10 for further information.

Net G&A on a per boe basis is expected to continue to decrease as the Company increases its operated capital expenditures over the last three months of 2017 resulting in increased G&A capitalization.

Share-Based Compensation

(\$000s)	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Equity settled share-based compensation	\$ 4,866	\$ 3,180	\$ 14,637	\$ 9,011
Cash settled share-based compensation	2,968	6,580	3,823	11,526
Share appreciation rights recoveries	(6)	—	(60)	—
Total net expense	\$ 7,828	\$ 9,760	\$ 18,400	\$ 20,537

Share-based compensation expense was \$18.4 million for the nine months ended September 30, 2017 compared to \$20.5 million for the same period in 2016.

Equity settled share-based compensation expense was \$4.9 million for the three months ended September 30, 2017 compared to \$3.2 million for the same period in 2016. Equity settled share-based compensation includes the Company's stock option plan and the restricted share unit ("RSU") plan pursuant to which RSUs and performance based RSUs ("PSUs") may be awarded. The increase from the prior year is related to issuance of new options, RSUs, and PSUs, as applicable, under the plans and an increased Black-Scholes value in the current year as compared to the prior year. Overall the number of stock options outstanding has decreased from December 31, 2016 while the number of RSUs and PSUs outstanding has increased.

Cash settled share-based compensation relates to the Company's cash settled incentive plans and includes share appreciation rights ("SARs"), cash settled restricted share units ("CRSUs") and deferred share units ("DSUs"). The CRSU plan is a new cash settled plan that will replace the current SAR plan as granted SAR's vest, and are exercised. There will be no SAR grants going forward. For the three months ended September 30, 2017 there was an expense of \$3.0 million related to cash settled incentive plans compared to \$6.6 million expense for the same period in 2016. Obligations for payments of cash under the Company's cash settled incentive plans are accrued as expense over the vesting period based on the fair value of the units as described in note 13 of the interim financial statements for the three and nine months ended September 30, 2017. As at September 30, 2017, the total cash settled incentive plans liability accrued is \$15.4 million (December 31, 2016 - \$13.5 million).

Depletion, Depreciation and Amortization Expense ("DD&A")

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
DD&A expense (000s)	\$ 28,755	\$ 31,917	\$ 79,070	\$ 92,644
Per unit (\$/boe) ⁽¹⁾	8.64	11.66	8.43	11.55

⁽¹⁾ DDA per unit (\$/boe) is calculated using Company DDA working interest production volumes and does not include inventory adjustments.

Third quarter 2017 DD&A was \$28.8 million (\$8.64/boe) compared to \$31.9 million (\$11.66/boe) for the same period in 2016. This decrease is due to the significant increase in proved and probable reserves and a change in the CGU production mix from the prior comparative period.



Foreign Exchange Loss (Gain)

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Foreign exchange (gain) loss (\$000s)	\$ 1,149	\$ 176	\$ 206	\$ (284)
Foreign Exchange Rates				
USD\$/CAD\$ ⁽¹⁾	1.25	1.30	1.31	1.32
USD\$/Colombian peso ⁽¹⁾	2,976	2,946	2,940	3,063

⁽¹⁾ Calculated based on Company working interest production volumes.

The Company's main exposure to foreign currency risk relates to the pricing of foreign currency denominated in Canadian dollars and Colombian pesos, as the Company's functional currency is the US dollar. The Company has exposure in Colombia and Canada on costs, such as capital expenditures, local wages, royalties and income taxes, all of which may be denominated in local currencies. The main drivers of foreign exchange (gains) losses are the revaluation of the Colombian peso denominated income tax, accounts payable and accounts receivable to USD at period end dates. During the three months ended September 30, 2017, the total foreign exchange loss was \$1.1 million (three months ended September 30, 2016 – loss of \$0.2 million). For the three months ended September 30, 2017, \$0.2 million foreign exchange loss was realized and \$1.0 million foreign exchange loss was unrealized (3 months ended September 30, 2016 - \$0.3 million foreign exchange loss is realized and \$0.1 million foreign exchange gain is unrealized). Unrealized foreign exchange gains and losses may be reversed in the future as a result of fluctuations in exchange rates and are recorded in the Company's consolidated statement of comprehensive income (loss).

The Company reviews its exposure to foreign currency variations on an ongoing basis and maintains USD cash deposits primarily in Canada, Colombia and Barbados.

Foreign Exchange Sensitivity Analysis

Cost component	Estimated percent of cost denominated in local currency	\$/boe Impact of change in local currency/\$USD exchange rate	
		10% appreciation of local currency	10% depreciation of local currency
Production expense	80%	\$ 0.44	\$ (0.44)
Transportation expense	50%	\$ 0.54	\$ (0.54)
G&A expense	100%	\$ 0.27	\$ (0.27)

The table above displays the estimated per boe impact of a change in Parex' local currencies and the effect on Parex' key cost components. The component impact in \$/boe terms uses Q3 2017 per boe costs. This analysis ignores all other factors impacting cost structure including efficiencies, cost reduction strategies, etc.

Net Finance Expense (Income)

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Bank charges and credit facility fees	\$ 1,036	\$ 953	\$ 2,737	\$ 2,275
Accretion on decommissioning and environmental liabilities	957	463	2,966	1,303
Interest and other income	(624)	(81)	(1,500)	(962)
Colombian net wealth tax	—	—	894	2,228
Net finance expense	\$ 1,369	\$ 1,335	\$ 5,097	\$ 4,844

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Non-cash finance expense	\$ 957	\$ 463	\$ 2,966	\$ 1,303
Cash finance expense	412	872	2,131	3,541
Net finance expense	\$ 1,369	\$ 1,335	\$ 5,097	\$ 4,844



Bank taxes and credit facility fees relate to bank taxes paid in Colombia and the standby fees related to the undrawn credit facility. Credit facility fees have decreased due to the voluntary reduction in the credit facility to \$100.0 million at September 30, 2017 (December 31, 2016 - \$175.0 million).

On December 23, 2014 the Colombian government passed a law imposing a Net Wealth Tax ("NWT") levied on Colombian businesses. The tax is assessed and becomes payable on the opening equity as at January 1st of each year beginning in 2015 extending until 2017, at rates from 1.15% in 2015 to 0.4% in 2017. The Company's NWT for 2017 is \$0.9 million and the entire amount was accrued during the three months ended March 31, 2017 and has been paid in two equal semi-annual installments in 2017.

Risk Management

Management of cash flow variability is an integral component of Parex' business strategy. Changing business conditions are monitored regularly and, where material, reviewed with the Board of Directors to establish risk management guidelines to be used by management. The risk exposure inherent in movements in the price of crude oil, fluctuations in the US/COP exchange rate and interest rate movements are all proactively reviewed by Parex and as considered appropriate may be managed through the use of derivatives primarily with financial institutions that are members of Parex' syndicated bank credit facility. The Company considers these derivative contracts to be an effective means to manage and forecast cash flow.

Parex has elected not to apply IFRS prescribed "hedge accounting" rules and, accordingly, pursuant to IFRS the fair value of the financial contracts is recorded at each period-end. The fair value may change substantially from period to period depending on commodity and foreign exchange forward strip prices for financial contracts outstanding at the balance sheet date. The change in fair value from period-end to period-end is reflected in the earnings for that period. As a result, earnings may fluctuate considerably based on the period-ending commodity and foreign exchange forward strip prices.

a) Risk Management Contracts - Brent Crude

The following is a summary of the ICE Brent priced crude oil risk management contracts in place during the nine months ended September 30, 2017:

Period Hedged	Reference	Volume bbls/d	Sold Put	Purchased Put	Sold Call	Premium
January 1, 2017 to February 28, 2017	ICE Brent	5,000	\$ 44.00	\$ 48.00	\$ 63.35	—
January 1, 2017 to March 31, 2017	ICE Brent	5,000	\$ 40.00	\$ 45.00	\$ 59.40	—
April 1, 2017 to June 30, 2017	ICE Brent	5,000	\$ 40.00	\$ 45.00	\$ 64.00	—
April 1, 2017 to September 30, 2017	ICE Brent	5,000	\$ 40.00	\$ 50.00	—	1.30
July 1, 2017 to September 30, 2017	ICE Brent	5,000	\$ 45.00	\$ 50.00	—	0.95
October 1, 2017 to December 31, 2017	ICE Brent	5,000	\$ 40.00	\$ 45.00	\$ 61.75	—
January 1, 2018 to March 31, 2018	ICE Brent	5,000	\$ 45.00	\$ 48.00	—	0.53

The table below summarizes the loss on the commodity risk management contracts:

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Realized (gain) on commodity risk management contracts	\$ (263)	\$ (319)	\$ (624)	\$ (949)
Premiums paid on commodity risk management contracts	438	1,212	1,627	6,528
Unrealized (gain) loss on commodity risk management contracts	2,120	(3,743)	(1,117)	3,702
Total	\$ 2,295	\$ (2,850)	\$ (114)	\$ 9,281

The Company's unrealized derivative position on risk management contracts for the three and nine month periods ended September 30, 2017 was a \$2.1 million loss and \$1.1 million gain (three and nine month periods ended September 30, 2016 – gain of \$3.7 million and loss of \$3.7 million). The net unrealized gain for the nine months ended September 30, 2017 is primarily attributable to the Brent forward benchmark price decreasing since the time the derivative contracts were entered into. The realized loss on commodity risk management contracts includes premiums paid for the nine month period ended September 30, 2017 of \$1.6 million (nine month period ended September 30, 2016 - \$6.5 million). The premiums allowed Parex to enter into contracts that had higher purchase put and higher ceiling call options prices than without the premiums.



Subsequent to September 30, 2017, Parex entered into the following ICE Brent priced crude oil risk management contracts:

Period Hedged	Reference	Volume bbls/d	Sold Put	Purchased Put	Sold Call	Premium
January 1, 2018 to March 31, 2018	ICE Brent	5,000	\$ 47.00	\$ 50.00	—	\$ 0.40
January 1, 2018 to March 31, 2018	ICE Brent	5,000	\$ 47.00	\$ 50.00	—	\$ 0.25

Income Tax

The components of tax expense for the three and nine months ended September 30, 2017 and 2016 were as follows:

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Current tax expense	\$ 16,166	\$ 1,951	\$ 28,528	\$ 1,657
Deferred tax expense (recovery)	(29,929)	1,002	(11,589)	(20,132)
Tax expense (recovery)	\$ (13,763)	\$ 2,953	\$ 16,939	\$ (18,475)

The current and future tax (recovery) expense relates to the Company's operations in Colombia. Current tax in the third quarter of 2017 was \$16.2 million expense as compared to \$2.0 million expense in the comparative period. The increase in the current tax expense from Q2 2017 of \$7.5 million is a result of increased Colombian cash flows as a result of the increase in realized prices, and costs lower than forecast. Also impacting previous current income tax estimates was the lower capital spending and lower dry-hole write-offs than were previously forecast. The completion of a voluntary tax restructuring impacted current tax in the quarter by approximately \$6.0 million (see below).

Deferred tax in the third quarter of 2017 was a recovery of \$29.9 million (\$1.0 million expense for the three months ended September 30, 2016). The main driver of the recovery in the third quarter of 2017 was a result of a voluntary tax reorganization (see below).

Tax Restructuring

Effective July 1, 2017 the Company entered into an intercompany purchase/sale agreement between two of its subsidiaries, whereby certain assets were effectively sold and their respective working interests were consolidated into one subsidiary. The purpose of the transaction was to make the Company's tax structure more efficient for future years. The impact of this restructuring is that the company incurred recapture and capital gains taxes in 2017 however has gained increased tax basis in the consolidated entity.

After completing the transaction, the Company has recorded the full impact of the transaction with the benefit of the restructuring beginning to be realized in the fourth quarter of 2017. Beginning in the fourth quarter of 2017 and going forward for 2018 we expect the Company's effective current tax rate to be approximately 20% of Colombian segmented cash flows. For 2018 using our budget Brent crude price assumption of \$55/bbl, our estimated current tax expense is expected to be \$60.0-\$65.0 million.

The benefit of the transaction is expected to reduce over time but is dependent upon global oil prices and other factors. The deferred tax recovery in the third quarter is a consequence of the transaction.

Capital Expenditures

For the three months ended September 30, (\$000s)	Colombia		Canada		Total	
	2017	2016	2017	2016	2017	2016
Acquisition of unproved properties	\$ 1,980	\$ 52	\$ —	\$ —	\$ 1,980	\$ 52
Geological and geophysical	40	553	—	—	40	553
Drilling and completion	43,752	22,897	—	—	43,752	22,897
Well equipment and facilities	5,658	2625	—	—	5,658	2625
Other	—	153	4	33	4	186
Total capital expenditures	\$ 51,430	\$ 26,280	\$ 4	\$ 33	\$ 51,434	\$ 26,313



For the nine months ended September 30, (\$000s)	Colombia		Canada		Total	
	2017	2016	2017	2016	2017	2016
Acquisition of unproved properties	\$ 4,076	\$ 369	\$ —	\$ —	\$ 4,076	\$ 369
Geological and geophysical	(29)	823	—	—	(29)	823
Drilling and completion	122,691	35,527	—	—	122,691	35,527
Well equipment and facilities	19,103	6,198	—	—	19,103	6,198
Other	136	1,699	28	126	164	1,825
Total capital expenditures	\$ 145,977	\$ 44,616	\$ 28	\$ 126	\$ 146,005	\$ 44,742

Capital Expenditures Summary

During the nine months ended September 30, 2017 the Company incurred \$146.0 million of capital expenditures compared to \$44.7 million in the same period of 2016. During Q3, 2017 the Company drilled 7 gross (4.75 net) wells, compared to 4 gross (2.65 net) wells in the comparative period.

During Q3, 2017, total drilling and completion costs were \$43.8 million of which the majority related to drilling, completion and capitalized workover costs at Block LLA-34, Cabrestero Block, Capachos Block and Aguas Blancas. In the third quarter of 2017 the Company's Colombian operations primarily utilized four drilling rigs and four service rigs between the operated and non-operated properties.

During the nine months ended September 30, 2017 capital expenditures of \$146.0 million were self funded from funds flow from operations of \$185.7 million. The Company strives to fund its annual capital expenditures from funds flow and has demonstrated this goal since 2012 however on a quarterly basis funds flow may be greater or less than capital expenditures due to timing of capital programs and other variables.

Summary of Quarterly Results

Three months ended (\$000s)	Sept. 30, 2017	June 30, 2017	March 31, 2017	Dec. 31, 2016
Average daily oil and natural gas production (boe/d)	36,195	34,291	32,591	31,049
Average realized sales price – oil and natural gas (\$/boe)	48.07	46.84	48.72	44.84
Financial (000s except per share amounts)				
Oil sales	\$ 159,929	\$ 145,406	\$ 150,142	\$ 131,858
Funds flow provided by operations	\$ 65,998	\$ 51,763	\$ 67,906	\$ 51,791
Per share – basic	0.43	0.34	0.44	0.34
Per share – diluted ⁽¹⁾	0.42	0.33	0.43	0.33
Net income (loss)	\$ 55,527	\$ 3,524	\$ 40,106	\$ (45,439)
Per share – basic	0.36	0.02	0.26	(0.30)
Per share – diluted	0.35	0.02	0.26	(0.30)
Capital Expenditures, excluding corporate acquisitions	\$ 51,434	\$ 59,008	\$ 35,563	\$ 66,890
Total assets (end of period)	\$ 1,057,859	\$ 1,015,540	\$ 984,855	\$ 918,671
Working capital surplus (end of period) ⁽²⁾	\$ 140,292	\$ 128,347	\$ 131,056	\$ 93,290

⁽¹⁾Non-GAAP term. See "Non-GAAP Terms" below.

⁽²⁾Working capital does not include the undrawn amount available under the syndicated bank credit facility.



Three months ended (\$000s)	Sept. 30, 2016	June 30, 2016	March 31, 2016	Dec. 31, 2015
Average daily oil and natural gas production (boe/d)	29,754	29,136	28,900	28,588
Average realized sales price - oil (\$/boe)	40.19	39.74	27.10	36.69
Financial (000s except per share amounts)				
Oil and gas sales	\$ 127,541	\$ 104,571	\$ 81,518	\$ 107,816
Funds flow provided by operations	\$ 45,091	\$ 31,792	\$ 15,457	\$ 33,628
Per share – basic	0.30	0.21	0.10	0.22
Per share – diluted ⁽¹⁾	0.29	0.20	0.10	0.22
Net income (loss)	6,811	(185)	\$ (7,630)	\$ (3,474)
Per share – basic	0.04	0.00	(0.05)	(0.02)
Per share – diluted	0.04	0.00	(0.05)	(0.02)
Capital Expenditures, excluding corporate acquisitions	\$ 26,313	\$ 13,922	\$ 4,507	\$ 23,611
Total assets (end of period)	\$ 947,354	\$ 921,665	\$ 943,675	\$ 957,966
Working capital surplus (end of period) ⁽²⁾	\$ 117,747	\$ 97,532	\$ 79,955	\$ 76,708

⁽¹⁾Non-GAAP term. See "Non-GAAP Terms" below.

⁽²⁾Working capital does not include the undrawn amount available under the syndicated bank credit facility.

Factors that Caused Variations Quarter Over Quarter

During the third quarter of 2017, production of 36,195 boe/d was in excess of production for the previous quarter ended June 30, 2017. Revenue was higher than the previous quarter due to an increased sales volumes and an increase in world oil prices in the period. Funds flow from operations was higher than the previous quarter also due to increased sales volumes and realized sales prices per barrel and due to a one-time payment in the previous quarter related to a legal settlement. Capital expenditures for the third quarter of 2017 were \$51.4 million compared to \$59.0 million in the prior quarter mainly related to drilling on Block LLA-34, Cabretero Block, Capachos Block and Aguas Blancas field. Net income in the period increased largely due to a recovery in deferred tax in the amount of \$29.9 million.

During the second quarter of 2017, production of 34,291 boe/d was in excess of production for the previous quarter ended March 31, 2017. Revenue was slightly lower than the previous quarter mainly due to a decrease in world oil prices in the period. Funds flow from operations was lower than the previous quarter due to a one-time payment of \$15.0 million related to a legal settlement. Adjusting for this one-time payment, funds flow increased to \$66.8 million, which is slightly lower than the previous quarter. Working capital was \$128.3 million compared to \$131.1 million at March 31, 2017. Capital expenditures for the second quarter of 2017 were \$59.0 million compared to \$35.6 million in the prior quarter mainly related to drilling on Block LLA-34, Cabretero Block, and Aguas Blancas field.

During the first quarter of 2017, production of 32,591 boe/d was in excess of oil production for the previous quarter ended December 31, 2016. Revenue and funds flow from operations were higher than the previous quarter mainly due to an increase in realized sales prices per barrel. Working capital has increased to \$131.1 million from \$93.3 million at December 31, 2016 mainly due to funds flow provided by operating activities of \$67.9 million being in excess of capital expenditures of \$35.6 million.

In Q4 2016, production was 31,049 boe/d, an increase of 4 percent over the previous quarter ended September 30, 2016. Working capital decreased to \$93.3 million from \$117.7 million at September 30, 2016. This was due to capital expenditures of \$66.9 million for the fourth quarter of 2016 being in excess of funds flows provided by operations of \$51.8 million; and an accrual for the 2017 current portion of asset retirement and environmental obligations in the amount of \$10.9 million. Capital expenditures increased significantly in the fourth quarter compared to the third quarter of 2016 as the company drilled 10 wells (6.35 net) in Q4, 2016 compared to 4 gross (2.65 net) wells during Q3, 2016.

Please refer to "Financial and Operating Results" for detailed discussions on variations during the comparative quarters and to Parex' previously issued annual and interim MD&As for further information regarding changes in prior quarters.



Liquidity and Capital Resources

As at September 30, 2017 the Company had a working capital surplus of \$140.3 million, excluding funds available under the credit facility, as compared to working capital surplus at December 31, 2016 of \$93.3 million. Bank debt was \$nil as at September 30, 2017, December 31, 2016 and September 30, 2016. The credit facility has a current borrowing base of \$100.0 million (December 31, 2016 - \$175.0 million) and is subject to a borrowing base redetermination to be completed by the end of May 2018. At September 30, 2017 Parex held \$195.9 million of cash, compared to \$149.2 million at December 31, 2016 and \$132.0 million at September 30, 2016. The Company's cash balances reside in current accounts, the majority of which are held on account in Canada and Barbados in USD. The increase in the Company's cash and working capital positions from prior periods is a result of the Company generating cash flow in excess of capital expenditures for the nine months ended September 30, 2017.

Parex' syndicated senior secured credit facility with a syndicate of banks has a current borrowing base of \$100.0 million. Key covenants include a rolling four quarters total funded debt to adjusted EBITDA test of 3:50:1, and other standard business operating covenants. Given there is \$nil balance drawn on the facility as at September 30, 2017, the Company is in compliance with all covenants. The next review is scheduled to occur at the end of May 2018. Parex voluntarily reduced the borrowing base on the credit facility to \$100.0 million from \$175.0 million at the semi-annual review in May 2017. This was done to reduce costs associated with the credit facility. As the Company currently has \$nil bank debt and no plans in 2017 to utilize the credit facility, this voluntary reduction is not expected to impact the Company's current or future operations or reduce the 2017 or 2018 outlook.

Refer to note 20 - Commitments of the interim financial statements for the period ended September 30, 2017 for a description of the performance guarantee facility with EDC as well as the unsecured letters of credit.

Outstanding Share Data

Parex is authorized to issue an unlimited number of voting common shares without nominal or par value. As at September 30, 2017 the Company had 154,555,773 common shares outstanding.

The Company has a stock option and RSU (which includes PSUs) plan. The plans provide for the issuance of stock options, RSUs and PSUs to the Company's officers, executive and certain employees to acquire common shares. The maximum number of stock options, RSUs and PSUs reserved for issuance under the two plans may not exceed 10 percent of the number of common shares issued and outstanding. RSU's (which includes PSUs) reserved for issuance may not exceed 4 percent of the common shares issued and outstanding.

As at November 7, 2017 Parex has the following securities outstanding:

	Number	%
Common shares	154,667,491	94 %
Stock options	6,946,437	4 %
Restricted and performance share units	2,941,436	2 %
	164,555,364	100%

As of the date of this MD&A, total stock options, RSUs and PSUs outstanding represent approximately 6 percent of the total issued and outstanding common shares.

Contractual Obligations, Commitments and Guarantees

In the normal course of business, Parex has entered into arrangements and incurred obligations that will affect the Company's future operations and liquidity. These commitments primarily relate to exploration work commitments including seismic and drilling activities. The Company has discretion regarding the timing of capital spending for exploration work commitments, provided that the work is completed by the end of the exploration periods specified in the contracts or the Company can negotiate extensions of the exploration periods. Given the low oil price environment the Colombian energy regulator ("ANH") has instituted means by which Companies can apply for extensions of phase commitments until oil prices improve. The Company has been very proactive in applying for extensions on many blocks that will assist with the Company matching cash flows from operations with capital expenditures. The Company's exploration commitments are described in the Company's AIF under "Description of Business - Principal Properties". These obligations and commitments are considered in assessing cash requirements in the discussion of future liquidity.

In Colombia, the Company has provided guarantees to the ANH and Empresa Colombiana de Petroleos S.A. ("Ecopetrol") which on September 30, 2017 were \$141.7 million (December 31, 2016 - \$148.7 million) to support the exploration work commitments on its blocks. The guarantees have been provided in the form of letters of credit for varying terms. Export Development Canada ("EDC") has provided performance security guarantees



under the Company's \$250.0 million (December 31, 2016 - \$200.0 million) performance guarantee facility to support approximately \$116.6 million (December 31, 2016 - \$126.4 million) of the letters of credit issued on behalf of Parex at September 30, 2017. The letters of credit issued to the ANH and Ecopetrol are reduced from time to time to reflect the work performed on the various blocks.

The following table summarizes the Company's estimated undiscounted commitments as at September 30, 2017:

(000s)	Total	<1 year	1 – 3 years	3 – 5 years	>5 years
Exploration	\$ 152,181	1,200	150,981	—	—
Office and accommodations ⁽¹⁾	7,818	1,709	2,246	1,966	1,897
Decommissioning and Environmental Obligations	87,743	10,902	—	—	76,841
Total	\$ 247,742	13,811	153,227	1,966	78,738

(1)Includes minimum lease payment obligations associated with leases for office space and accommodations.

Decommissioning Liabilities

	Decommissioning	Environmental	Total
Balance, December 31, 2015	\$ 26,811	\$ 8,588	\$ 35,399
Additions	5,241	703	5,944
Settlements of obligations during the year	(75)	(103)	(178)
Accretion expense	1,432	399	1,831
Additions related to change in estimate - inflation and discount rates	7,697	1,482	9,179
Additions related to change in estimate - costs	(2,386)	1,677	(709)
Foreign exchange (gain)	—	(320)	(320)
Balance, December 31, 2016	\$ 38,720	\$ 12,426	\$ 51,146
Additions	3,839	1,345	5,184
Additions related to change in estimate - inflation and discount rates	(5,467)	(1,399)	(6,866)
Settlements of obligations during the period	(160)	(159)	(319)
Accretion expense	1,895	1,071	2,966
Foreign exchange loss (gain)	1,172	(91)	1,081
Balance, September 30, 2017	\$ 39,999	\$ 13,193	\$ 53,192
Current obligation	(4,074)	(6,828)	(10,902)
Long-term obligation	\$ 35,925	\$ 6,365	\$ 42,290

The total environmental, decommissioning and restoration obligations were determined by management based on the estimated costs to settle environmental impact obligations incurred and to reclaim and abandon the wells and well sites based on contractual requirements. The obligations are expected to be funded from the Company's internal resources available at the time of settlement.

The total decommissioning and environmental liability is estimated based on the Company's net ownership in wells drilled as at September 30, 2017, the estimated costs to abandon and reclaim the wells and well sites and the estimated timing of the costs to be paid in future periods. The total undiscounted amount of cash flows required to settle the Company's decommissioning liability is approximately \$71.5 million as at September 30, 2017 (December 31, 2016 – \$92.1 million) with the majority of these costs anticipated to occur after 2029. A risk-free discount rate of 7.5 percent and an inflation rate of 4.0 percent were used in the valuation of the liabilities (December 31, 2016 – 7.2 percent risk-free discount rate and a 7.5 percent inflation rate). The risk-free discount rate and the inflation rate used in 2017 are based on forecast Colombia rates.

Included in the decommissioning liability is \$4.1 million (December 31, 2016 – \$4.2 million) that is classified as a current obligation.

The total undiscounted amount of cash flows required to settle the Company's environmental liability is approximately \$16.3 million as at September 30, 2017 (December 31, 2016 – \$16.1 million) with the majority of these costs anticipated to occur in 2018 or later in Colombia. A risk-free discount rate of 7.5 percent and an inflation rate of 4.0 percent were used in the valuation of the liabilities (December 31, 2016 – 7.2 percent risk-free discount rate and a 7.5 percent inflation rate). The risk-free discount rate and the inflation rate used in 2017 are based on forecast Colombia rates.

Included in the environmental liability is \$6.8 million (December 31, 2016 – \$6.7 million) that is classified as a current obligation.



Decommissioning liabilities are considered critical accounting estimates. There are significant uncertainties related to decommissioning expenditures and the impact on the financial statements could be material. The eventual timing of and costs for these expenditures could differ from current estimates. The main factors that can cause expected estimated cash flows in respect of decommissioning liabilities to change are:

- Changes in laws and legislation;
- Construction of new facilities;
- Change in commodity price;
- Change in the estimate of oil reserves and the resulting amendment to the life of reserves;
- Changes in technology; and
- Execution of decommissioning liabilities.

Advisory on Forward-Looking Statements

Certain information regarding Parex set forth in this MD&A, including assessments by the Company's management of the Company's plans and future operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. The use of any of the words "plan", "expect", "forecast", "project", "intend", "believe", "anticipate", "estimate" or other similar words, or statements that certain events or conditions "may" or "will" occur are intended to identify forward-looking statements. Such statements represent the Company's internal projections, estimates or beliefs concerning, among other things, future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), competitive advantages, plans for and results of drilling activity, environmental matters, business prospects and opportunities. These statements are only predictions and actual events or results may differ materially. Although the Company's management 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, competitive, political and social uncertainties and contingencies. Many factors could cause the Company's actual results to differ materially from those expressed or implied in any forward-looking statements made by, or on behalf of, Parex. In particular, forward-looking statements contained in this MD&A include, but are not limited to, statements with respect to:

- the Company's operational strategy and focus, including targeted jurisdictions and technologies used to execute its strategy;
- the Company's approach to manage subsurface and commercial risks;
- the Company's exploration blocks subject to farm-in and earning requirements and the effect on the Company's land holdings as lands deemed non-commercial are released;
- activities to be undertaken in various areas including the fulfillment of exploration commitments and farm-in obligations;
- terms of exploration and production contracts and the timing of release of exploration property deemed non-commercial in respect of the exploration contracts;
- the Company's capital program budget for 2017, including the expected allocation of such expenditures and the Company's plans to fund its 2017 capital program from funds flow from operations;
- the Company's forecasted 2017 oil production, capital budget and funds from operations;
- expectations of transportation costs for the remainder of 2017;
- expected royalty rates and effect of changes in pricing on the Company's overall royalty as a percentage of sales and the calculation and applicability of the HPR;
- the Company's expectations regarding the per boe impact caused by appreciation and depreciation of the Colombian peso;
- the effect of the Colombian peso/US\$ exchange rate on the variability of transportation costs;
- the expected effect of increased capital expenditures on 2017 G&A;
- terms and cost of share-based compensation plans, including stock option plan, restricted share unit (including preferred share units) plan, deferred share unit plan, share appreciation rights and cash settled restricted share unit plan;
- foreign currency risk and the ability to reverse unrealized foreign exchange gains and losses in the future;
- the Company's risk management strategy and the use of derivatives primarily with financial institutions to manage movements in the price of crude oil, fluctuations in the US/COP exchange rate and interest rate movements;
- terms of the Company's risk management contracts and the Company's ability to manage and forecast cash flow;
- the Company's expected 2017 NWT;
- the Company's estimated amount of current tax expense for 2017;
- the expected impact of the voluntary tax restructuring completed in Q3, 2017;
- the Company's estimated effective current tax rate for fourth quarter of 2017 and for 2018;
- the Company's estimated current tax expense for 2018;
- terms of the Company's credit facility including the timing of the next borrowing base redetermination;
- the Company's expectation that the next redetermination of its credit facility will not impact its current or future operations or reduce the 2017 or 2018 outlook;
- terms of the Company's exploration and other contractual commitments and their timing of settlement;



- estimated amounts, timing and the anticipated sources of funding for the Company's environmental, decommissioning and restoration obligations; and
- effect of business and environmental risks on the Company.

These forward-looking statements are subject to numerous risks and uncertainties, including but not limited to: the impact of general economic conditions in Canada and Colombia; industry conditions including changes in laws and regulations including adoption of new environmental laws and regulations, and changes in how they are interpreted and enforced in Canada and Colombia; continued volatility in market prices for oil; the impact of significant declines in market prices for oil; competition; lack of availability of qualified personnel; the results of exploration and development drilling and related activities; partner approval of capital work programs and other matters requiring approval; imprecision in reserve and resource estimates; the production and growth potential of Parex' assets; obtaining required approvals of regulatory authorities in Canada and Colombia; risks associated with negotiating with foreign governments as well as country risk associated with conducting international activities; fluctuations in foreign exchange or interest rates; environmental risks; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and natural gas industry; ability to access sufficient capital from internal and external sources; risk that the Company will not be able to obtain contract extensions or fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its undeveloped properties; risk of failure to achieve the anticipated benefits associated with acquisitions; failure of counterparties to perform under the terms of their contracts; the risks discussed under "Risk Factors" in the Company's AIF and under "Decommissioning and Environmental Liabilities" and "Business Environment and Risks" in this MD&A, and other factors, many of which are beyond the control of the Company. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect the Company's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com).

Although the forward-looking statements contained in this MD&A are based upon assumptions which management believes to be reasonable, the Company cannot assure investors that actual results will be consistent with these forward-looking statements. With respect to forward-looking statements contained in this MD&A, Parex has made assumptions regarding, among other things: current and future commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; uninterrupted access to areas of the Company's operations and infrastructure; future exchange rates; the price of oil; the impact of increasing competition; conditions in general economic and financial markets; availability of drilling and related equipment; effects of regulation by governmental agencies; recoverability of reserves and future production rates; royalty rates; future operating costs; foreign exchange rates; the status of litigation; timing of drilling and completion of wells; that the Company will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; that the Company's conduct and results of operations will be consistent with its expectations; that the Company will have the ability to develop the Company's oil and gas properties in the manner currently contemplated; current or, where applicable, proposed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; that the estimates of the Company's reserves volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects; that the Company will be able to obtain contract extensions or fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its undeveloped properties; and other matters. The ability of the Company to carry out its business plan is primarily dependent upon the continued support of its shareholders, the discovery of economically recoverable reserves and the ability of the Company to obtain financing to develop such reserves.

Forward-looking statements and other information contained in this MD&A concerning the oil and natural gas industry in the countries in which it operates and the Company's general expectations concerning this industry are based on estimates prepared by Management using data from publicly available industry sources as well as from resource reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Company believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Company is not aware of any material misstatements regarding any industry data presented herein, the oil and natural gas industry involves numerous risks and uncertainties and is subject to change based on various factors.

Management has included forward looking information and the above summary of assumptions and risks related to forward-looking information in this MD&A in order to provide shareholders with a more complete perspective on the Company's current and future operations and such information may not be appropriate for other purposes. The Company's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do, what benefits Parex will derive there from. These forward-looking statements are made as of the date of this MD&A and Parex disclaims any intent or obligation to update publicly any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

This MD&A may contain future oriented financial information ("FOFI") within the meaning of applicable securities laws. The FOFI has been prepared by management to provide an outlook of the Company's activities and results and may not be appropriate for other purposes. The FOFI has been prepared based on a number of assumptions including the assumptions discussed above. The actual results of operations of the Company and



the resulting financial results may vary from the amounts set forth herein, and such variations may be material. The Company and management believe that the FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments. FOFI contained in this MD&A was made as of the date of this MD&A and the Company disclaims any intention or obligations to update or revise any FOFI contained in this MD&A, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law.

Non-GAAP Terms

This report contains financial terms that are not considered measures under GAAP such as operating netback per boe, free cash flow and diluted funds flow per share that do not have any standardized meaning under IFRS and may not be comparable to similar measures presented by other companies. Management uses these non-GAAP measures for its own performance measurement and to provide shareholders and investors with additional measurements of the Company's efficiency and its ability to fund a portion of its future capital expenditures.

Diluted funds flow per share is calculated by dividing funds flow provided by operations by the weighted average number of shares outstanding. Parex presents diluted funds flow provided by operations per share whereby per share amounts are calculated using weighted-average shares outstanding, consistent with the calculation of earnings per share. The following table shows the variables used in the calculation of diluted funds flow per share:

(000s)	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Funds flow provided by operations	\$ 65,998	\$ 45,091	\$ 185,667	\$ 92,340
Weighted average number of shares for the purposes of basic funds flow	154,472	152,700	154,006	151,985
Dilutive effect of share options on potential common shares	3,463	3,308	3,838	3,154
Weighted average number of shares for the purposes of diluted funds flow	157,935	156,008	157,844	155,139

Adjusted EBITDA is defined as net income (loss) before interest, taxes, depletion and depreciation and adjusted for other non-cash items, transaction costs and extraordinary and non-recurring items. Adjusted EBITDA is solely used in the calculation of the bank covenant and is not considered a key performance measure by Management.

Operating netback per boe

The Company considers operating netbacks to be a key measure as they demonstrate Parex' profitability relative to current commodity prices. Below is a description of each component of the Company's operating netback and how it is determined.

Oil and natural gas sales per boe is determined by sales revenue excluding risk management contracts less non-cash oil revenue from overlifted Ocesa pipeline volumes divided by total equivalent sales volume including purchased oil volumes. A reconciliation of the calculation of oil and natural gas sales per boe is provided below:

(\$000s)	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Oil and natural gas revenue excluding risk management contracts	\$ 159,929	\$ 127,541	\$ 455,477	\$ 313,630
Denominator (BOEs)				
Company produced oil and natural gas sales in period	3,303,260	2,746,627	9,405,123	8,155,136
Purchased oil volumes sold	23,828	90,692	108,108	321,820
Overlifted oil volumes	—	335,772	—	335,772
Total oil and natural gas sales volumes	3,327,088	3,173,091	9,513,231	8,812,728
Sales price per boe	\$ 48.07	\$ 40.19	\$ 47.88	\$ 35.59



Royalties per boe is determined by dividing royalty expense by the total equivalent sales volume and excludes purchased oil volumes. A reconciliation of royalties per boe is provided below:

(\$000s)	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Royalty expense	13,015	\$ 8,927	\$ 38,688	\$ 23,967
Denominator (BOEs)				
Company produced oil and natural gas sales in period	3,303,260	2,746,627	9,405,123	8,155,136
Overlifted oil volumes returned to Ocesa pipeline	—	—	—	—
Total oil and natural gas sales volumes	3,303,260	2,746,627	9,405,123	8,155,136
Royalty expense per boe	\$ 3.94	\$ 3.25	\$ 4.11	\$ 2.94

Production expense per boe is determined by dividing production expense by the total equivalent sales volume and excludes purchased oil volumes. A reconciliation of production expense per boe is provided below:

(\$000s)	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Production Expense	\$ 18,191	\$ 12,341	\$ 49,943	\$ 37,886
Denominator (BOEs)				
Company produced oil and natural gas sales in period	3,303,260	2,746,627	9,405,123	8,155,136
Overlifted oil volumes returned to Ocesa pipeline	—	—	—	—
Total oil and natural gas sales volumes	3,303,260	2,746,627	9,405,123	8,155,136
Production expense per boe	\$ 5.51	\$ 4.49	\$ 5.31	\$ 4.65

Transportation expense per boe is determined by dividing the transportation expense by the total equivalent sales volumes including purchased oil volumes. A reconciliation of transportation expense per boe is provided below:

(\$000s)	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Transportation Expense	\$ 35,678	\$ 32,843	\$ 103,781	\$ 99,442
Denominator (BOEs)				
Company produced oil and natural gas sales in period	3,303,260	2,746,627	9,405,123	8,155,136
Overlifted oil volumes returned to Ocesa pipeline	—	—	—	—
Purchased oil volumes sold	23,828	90,692	108,108	321,820
Total oil and natural gas sales volumes	3,327,088	2,837,319	9,513,231	8,476,956
Transportation expense per boe	\$ 10.72	\$ 11.58	\$ 10.91	\$ 11.73

Free funds flow (deficiency) is determined by funds flow provided by operations less capital expenditures as follows:

(\$000s)	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Funds flow provided by operations	\$ 65,998	\$ 45,091	\$ 185,667	\$ 92,340
Capital expenditures, excluding corporate acquisitions	51,434	26,313	146,005	44,742
Free funds flow (deficiency)	\$ 14,564	\$ 18,778	\$ 39,662	\$ 47,598



Business Environment and Risks

There have been no significant changes during the nine months ended September 30, 2017 to the risks and uncertainties identified in the Company's AIF.

Internal Controls over Financial Reporting

There was no change in the Company's internal controls over financial reporting that occurred during the most recently completed period that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting.

Off-Balance-Sheet Arrangements

The Company did not enter into any off-balance-sheet arrangements during the nine months ended September 30, 2017.

Financial Instruments and Other Instruments

The Company's non-derivative financial instruments recognized in the consolidated balance sheet consist of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities. Non-derivative financial instruments are recognized initially at fair value. The fair values of the current financial instruments approximate their carrying value due to their short-term maturity.

Accounting Policies and Estimates

There is no impact on the condensed interim consolidated financial statements for the adoption of new accounting standards effective January 1, 2017. The accounting policies adopted are consistent with those of the previous financial year as described in note 3 of the Company's consolidated financial statements for the year ended December 31, 2016, except for the following:

Pursuant to the Restricted Share Unit ("RSU") plan, the Company may grant Performance Share Units ("PSUs") to certain employees. Compensation cost attributable to PSUs granted to certain employees of the Company is measured at fair value at the date of grant and expensed over the vesting period with a corresponding increase in contributed surplus. The fair value of each PSU granted is based on the share price at which the common shares of the Company traded for on the grant date. The performance share units may be granted with certain performance measures, specified at the grant date as determined by the Company's Board of Directors. Based upon the achievement of the performance measures, a pre-determined adjustment factor of between 0-2x is applied to PSUs eligible to vest at the end of the performance period. The expense recognized over the vesting period of PSUs is the fair value of the PSUs with an estimated adjustment factor. If the actual final adjustment factor is higher than estimated at grant, additional expense is recognized on vesting for the incremental fair value. Upon the exercise of the PSUs consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

The Company has a Cash Settled Restricted Share Unit ("CRSUs") plan which allows the Company to issue CRSUs to certain employees of Parex Colombia. Obligations for payments of cash under the foreign subsidiaries' CRSUs plan are accrued as compensation expense over the vesting period based on the fair value of CRSUs. The fair value of CRSUs is equal to the market price of the Company's common shares at the valuation date. In accordance with the fair value method, increases or decreases in the fair value of the CRSUs result in a corresponding change in the recorded liability. The accrued compensation for a right that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture. The CRSUs liability cannot be settled by the issuance of common shares.

In the current period the Company amended the terms of its Deferred Share Unit ("DSUs") plan which allows the Company to issue DSUs to certain non-employee directors of Parex Resources Inc. Previously DSUs were settled in shares or cash at the discretion of the Company. Going forward the DSUs will be settled in cash and the DSUs liability cannot be settled by the issuance of common shares. As DSUs vest immediately on issuance, obligations for payments of cash under the DSUs plan are accrued as compensation expense immediately on issuance based on the fair value of the DSUs. The fair value of DSUs at each reporting period is equal to the market price of the Company's common shares at the valuation date. In accordance with the fair value method, increases or decreases in the fair value of the DSUs result in a corresponding change in the recorded liability. The accrued compensation for a unit that is forfeited is adjusted by decreasing compensation cost in the period of forfeiture.

Cash and cash equivalents comprise cash on hand and other short-term highly liquid investments with maturities less than 3 months.

In future accounting periods, the Company will adopt the following IFRS standards issued but not yet effective:

IFRS 15 Revenue from Contracts with Customers - IFRS 15 "Revenue from Contracts with Customers" was issued in May 2014 and replaces IAS 18 "Revenue", IAS 11 "Construction Contracts" and related interpretations. The standard is required to be adopted for fiscal years beginning on or after January 1, 2018 either retrospectively or using a modified transaction approach, with early adoption permitted. IFRS 15 will be adopted by the Company on January 1, 2018. IFRS 15 provides clarification for recognizing revenue from contracts with customers and establishes a single



revenue recognition and measurement framework. The impact of the standard has been evaluated by the Company and is expected to have no material impact on the Company's financial statements. Additional disclosure may be required upon implementation of IFRS 15 in order to provide sufficient information to enable users to understand the nature, amount, timing, and uncertainty of revenue and cash flows arising from the contracts with customers.

IFRS 9 Financial Instruments - In July 2014, the IASB completed the final amendments of IFRS 9 "Financial Instruments". The Standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 "Financial Instruments: Recognition and Measurement". IFRS 9, as amended, includes a principle-based approach for classification and measurement of financial assets, a single 'expected loss' impairment model and a substantially-reformed approach to hedge accounting. The Standard will come into effect for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. This amendment will be adopted by the Company on January 1, 2018 and the Company does not expect the amendment to have a material impact on the Company's financial statements.

IFRS 16 Leases - IFRS 16 "Leases" was issued January 2016 and replaces IAS 17 "Leases". The standard introduces a single lessee accounting model for leases with required recognition of assets and liabilities for most leases. The standard is effective for fiscal years beginning on or after January 1, 2019 with early adoption permitted if the Company is also applying IFRS 15 "Revenue from Contracts with Customers". IFRS 16 will be adopted by the Company on January 1, 2019 and the Company is currently reviewing contracts that are identified as leases and assessing the impact that the adoption of the standard will have on the consolidated financial statements.

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*President and Chief Executive Officer***Kenneth G. Pinsky**
*Chief Financial Officer & Corporate Secretary***Stu R. Davie**
*Vice President Corporate Services***Lee DiStefano**
*President, Parex Colombia & Country Manager***Ryan W. Fowler**
*Sr. Vice President, Exploration & Business Development***Eric Furlan**
*Sr. Vice President of Engineering***Michael Kruchten**
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ABBREVIATIONS**Oil and Natural Gas Liquids**

bbls	barrels
mbbls	one thousand barrels
mmbbls	one million barrels
NGLs	natural gas liquids
bbls/d	barrels of oil per day
mbbls/d	one thousand barrels per day
BOE or boe	barrel of oil equivalent, using the conversion factor of 6 Mcf: 1 bbl
mboe	one thousand barrels of oil equivalent
mmboe	one million barrels of oil equivalent
bfpd	barrels of fluid per day
boe/d	barrels of oil equivalent per day
mcf	thousand cubic feet
bopd	barrels of oil per day
mcf/d	thousand cubic feet per day

Other

WTI	West Texas Intermediate
Brent	Brent Ice

"BOEs" may be misleading, particularly if used in isolation. A BOE conversion ratio of nine thousand cubic feet of natural gas to one barrel of oil equivalent (6 mcf: 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.