

CONSOLIDATED INTERIM FINANCIAL STATEMENTS
Consolidated Balance Sheets (unaudited)

As at (thousands of United States dollars)	NOTE	March 31, 2018	December 31, 2017
ASSETS			
Current assets			
Cash and cash equivalents		\$ 294,497	\$ 235,042
Accounts receivable	5	87,723	79,152
Prepays and other current assets		3,883	1,828
Crude oil inventory	6	3,802	3,038
		389,905	319,060
Deferred tax asset	15	20,320	20,815
Goodwill		73,452	73,452
Exploration and evaluation	7	126,074	107,144
Property, plant and equipment	8	620,146	601,437
		\$ 1,229,897	\$ 1,121,908
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities		\$ 101,784	\$ 103,509
Derivative financial instruments	19	393	116
Current income and equity tax payable	15	72,325	42,266
Current portion of decommissioning and environmental liabilities	12	9,632	9,768
		184,134	155,659
Other long-term liabilities	11	5,481	4,718
Decommissioning and environmental liabilities	12	49,436	42,912
Deferred tax liability	15	30,400	30,345
		269,451	233,634
Shareholders' equity			
Share capital	13	845,521	836,166
Contributed surplus		51,214	52,431
Retained Earnings (Deficit)		63,711	(323)
		960,446	888,274
		\$ 1,229,897	\$ 1,121,908

Commitments (note 21)

See accompanying Notes to the Interim Consolidated Financial Statements

Approved by the Board:



 Paul Wright
Director



 Ron Miller
Director

Interim Consolidated Statements of Comprehensive Income (unaudited)

For the three months ended March 31,

(thousands of United States dollars, except per share amounts)

	NOTE	2018	2017
Oil and natural gas sales	9	\$ 202,450	\$ 130,079
Royalties		(26,179)	(13,252)
Revenue		176,271	116,827
Commodity risk management contracts (loss) gain	19	(396)	1,318
		175,875	118,145
Expenses			
Production		19,202	15,389
Transportation		15,343	14,180
Purchased oil		1,436	2,374
General and administrative		8,155	7,740
Share-based compensation equity settled	13	3,513	4,726
Share-based compensation cash settled	14	771	1,803
Depletion, depreciation and amortization	8	22,439	24,409
Foreign exchange loss		4,579	1,584
		75,438	72,205
Finance (income)	11	(545)	(384)
Finance expense	11	1,640	2,638
Net finance expense		1,095	2,254
Net income before taxes		99,342	43,686
Income tax expense			
Current income tax expense	15	27,280	4,857
Deferred income tax expense (recovery)	15	550	(1,277)
		27,830	3,580
Net income and comprehensive income for the period		\$ 71,512	\$ 40,106
Basic net income per common share	16	\$ 0.46	\$ 0.26
Diluted net income per common share	16	\$ 0.45	\$ 0.26

See accompanying Notes to the Interim Consolidated Financial Statements



Consolidated Statements of Changes in Equity (unaudited)

For the three months ended March 31,
(thousands of United States dollars)

	2018		2017	
Share Capital				
Balance, beginning of period	\$	836,166	\$	822,227
Issuance of common shares under share-based compensation plans		13,028		4,841
Repurchase of shares		(3,673)		—
Balance, end of period	\$	845,521	\$	827,068
Contributed Surplus				
Balance, beginning of period	\$	52,431	\$	42,208
Share-based compensation		3,513		4,726
Options exercised		(4,730)		(1,931)
Balance, end of period	\$	51,214	\$	45,003
Retained Earnings (Deficit)				
Balance, beginning of period	\$	(323)	\$	(150,643)
Net income for the period		71,512		40,106
Repurchase of shares		(7,478)		—
Balance, end of period		63,711		(110,537)
Total Equity	\$	960,446	\$	761,534

See accompanying Notes to the Interim Consolidated Financial Statements



Consolidated Statements of Cash Flows (unaudited)

For the three months ended March 31,
(thousands of United States dollars)

	NOTE	2018	2017
Operating activities			
Net income		\$ 71,512	\$ 40,106
Add (deduct) non-cash items			
Depletion, depreciation and amortization	8	22,439	24,409
Non-cash finance expense	10	1,220	835
Share-based compensation equity settled	13	3,513	4,726
Share-based compensation cash settled	14	771	1,803
Deferred tax expense (recovery)	15	550	(1,277)
Unrealized foreign exchange loss		3,516	596
Unrealized (gain) loss on commodity risk management contracts	19	216	(2,507)
Abandonment costs paid		(875)	(200)
Stock appreciation rights paid		(1,961)	(585)
Funds flow provided by operations		100,901	67,906
Net change in non-cash working capital	17	11,792	(14,535)
Cash provided by operating activities		112,693	53,371
Investing activities			
Property, plant and equipment expenditures	8	(39,280)	(24,681)
Exploration and evaluation expenditures	7	(18,930)	(10,882)
Net change in non-cash working capital	17	7,498	14,553
Cash (used in) investing activities		(50,712)	(21,010)
Financing activities			
Issuance of common shares under share-based compensation plans	13	8,298	2,910
Common shares repurchased	13	(11,151)	—
Cash (used in) provided by financing activities		(2,853)	2,910
Increase in cash for the period		59,128	35,271
Impact of foreign exchange on foreign currency-denominated cash balances		327	130
Cash, beginning of period		235,042	149,246
Cash, end of period		\$ 294,497	\$ 184,647

Supplemental Disclosure of Cash Flow Information (note 17)
See accompanying Notes to the Interim Consolidated Financial Statements



Notes to the Condensed Interim Consolidated Financial Statements

For the period ended March 31, 2018

(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 South America.

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 May 8, 2018.

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

a) *Statement of compliance*

The condensed interim consolidated financial statements for the three months ended March 31, 2018 have been prepared in accordance with IAS 34, 'Interim financial reporting'. The condensed interim consolidated financial statements should be read in conjunction with the annual financial statements for the year ended December 31, 2017, which have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB").

These condensed interim consolidated financial statements were approved by the Board of Directors on May 8, 2018.

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, 2017.

3. Summary of Significant Accounting Policies

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, 2017, except for the following adoption of new accounting standards effective January 1, 2018:

a) **Adoption of IFRS 15, Revenues From Contracts With Customers**

The Company adopted IFRS 15, "Revenue from Contracts with Customers" on January 1, 2018. The Company used the retrospective adoption approach to adopt the new standard. In conjunction with the adoption of IFRS 15, the Company reviewed its revenue streams and major contracts with customers. As a result of this review, the Company changed the way it records revenue and transportation costs on certain oil sale contracts. The change resulted in a \$20.1 million reduction to revenue in the three months ended March 31, 2017 with a corresponding reduction of \$20.1 million to transportation expense. The effect of the reclassification on the prior period is presented below:



For the three months ended
(000s)

		March 31, 2017
Decrease in sales of crude oil	\$	(20,063)
Decrease in transportation expense		(20,063)
Impact on net income	\$	—

There was no material impact on the Company's net income and financial position resulting from this change and there was no effect to the opening deficit from the application of IFRS 15 to revenue contracts in progress at January 1, 2018. The additional disclosures required by IFRS 15 are detailed in Note 9 - Revenue.

The following accounting policy is applicable from January 1, 2018:

Parex principally generates revenue from the sale of commodities, which include crude oil and natural gas. Revenue associated with the sale of commodities is recognized when control is transferred from Parex to its customers. The Company's commodity sale contracts represent a series of distinct transactions. The Company considers its performance obligations to be satisfied and control to be transferred when all the following conditions are satisfied:

- Parex has transferred title and physical possession of the commodity to the buyer;
- Parex has transferred the significant risks and rewards of ownership of the commodity to the buyer; and
- Parex has the present right to payment.

Revenue is measured based on the consideration specified in a contract with a customer and excludes amounts collected on behalf of third parties. The Company sells its production of crude oil and natural gas pursuant to variable price contracts. The transaction price for variable price contracts is based on the commodity price, adjusted for quality, location and other factors. The amount of revenue recognized is based on the agreed transaction price with any variability in transaction price recognized in the same period. The Company does not have any contracts where the period between the transfer of the promised goods or services to the customer and payment by the customer exceeds one year. As a result, Parex does not adjust its revenue transactions for the time value of money.

Parex enters into contracts with customers that can have performance obligations that are unsatisfied (or partially unsatisfied) at the reporting date. The Company applies a practical expedient of IFRS 15 and does not disclose information about remaining performance obligations that have original expected durations of one year or less, or for performance obligations where the Company has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of the Company's performance completed to date. The company also applies a practical expedient of IFRS 15 that allows any incremental costs of obtaining contracts with customers to be recognized as an expense when incurred rather than being capitalized.

Contract modifications with the Company's customers could change the scope of the contract, the price of the contract, or both. A contract modification exists when the parties to the contract approve the modification either in writing, orally, or based on the parties' customary business practices. Contract modifications are accounted for either as a separate contract when there is an additional product at a stand alone selling price, or as part of the existing contract, through either a cumulative catch-up adjustment or prospectively over the remaining term of the contract, depending on the nature of the modification and whether the remaining products are distinct.

The Company's revenue transactions do not contain significant financing components.

b) Adoption of IFRS 9, Financial Instruments

Effective January 1, 2018, the Company adopted IFRS 9, Financial Instruments (IFRS 9), which replaced IAS 39, Financial Instruments: Recognition and Measurement (IAS 39). The Company applied the new standard retrospectively and the adoption of IFRS 9 did not have a material impact on the Company's consolidated financial statements and did not result in any adjustments to the amounts recognized in the Company's consolidated financial statements for the year ended December 31, 2017. The nature and effects of the key changes to the Company's accounting policies resulting from the adoption of IFRS 9 are summarized below.

Classification of Financial Assets and Financial Liabilities

IFRS 9 contains three principal classification categories for financial assets: measured at amortized cost, fair value through other comprehensive income (FVOCI) and fair value through profit or loss (FVTPL). The previous IAS 39 categories of held to maturity, loans and receivables and available for sale are eliminated. IFRS 9 bases the classification of financial assets on the contractual cash flow characteristics and the company's business model for managing the financial asset. Additionally, embedded derivatives are not separated if the host contract is a financial asset within the scope of IFRS 9. Instead, the entire hybrid contract is assessed for classification and measurement.



IFRS 9 largely retains the existing requirements in IAS 39 for the classification of financial liabilities. The differences between the two standards did not impact the Company at the time of transition.

The following table shows the original measurement categories under IAS 39 and the new measurement categories under IFRS 9 as at January 1, 2018 for each class of the Company's financial assets and financial liabilities:

Financial Instrument	Measurement Category ⁽¹⁾	
	IAS 39	IFRS 9
Cash and cash equivalents	Loans and receivables (measured at amortized cost)	Amortized cost
Accounts receivable	Loans and receivables (measured at amortized cost)	Amortized cost
Accounts payable and accrued liabilities	Other financial liabilities (measured at amortized cost)	Amortized cost
Derivative financial instruments	FVTPL	FVTPL

(1) There were no adjustments to the carrying amounts of financial instruments as a result of the change in classification from IAS 39 to IFRS 9.

Impairment of financial assets

IFRS 9 replaces the "incurred loss" model in IAS 39 with an "expected credit loss" ("ECL") model. The new impairment model applies to financial assets measured at amortized cost. Under IFRS 9, credit losses are recognized earlier than under IAS 39.

The ECL model applies to the Company's receivables. As at March 31, 2018, 99 percent of the Company's receivables were outstanding for less than 60 days. The average expected credit loss on the Company's trade accounts receivable was 0.2 percent at March 31, 2018.

On January 1, 2018, the Company identified the business model used to manage its financial assets and classified its financial instruments into the appropriate IFRS 9 categories as shown in the table above and applied the ECL model to financial assets classified as measured at amortized cost. The classification and measurement of financial instruments under IFRS 9 did not have a material impact on the Company's opening retained earnings as at January 1, 2018. In addition, the application of the ECL model to financial assets classified as measured at amortized cost did not result in a material adjustment on transition.

The following accounting policy is applicable from January 1, 2018:

Financial instruments are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets and liabilities are not offset unless the Company has the current legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously.

The Company characterizes its fair value measurements into a three-level hierarchy depending on the degree to which the inputs are observable, as follows:

- Level 1 inputs are quoted prices in active markets for identical assets and liabilities;
- Level 2 inputs are inputs, other than quoted prices included within Level 1, that are observable for the asset or liability either directly or indirectly; and
- Level 3 inputs are unobservable inputs for the asset or liability.

Classification and Measurement of Financial Assets

The initial classification of a financial asset depends upon the Company's business model for managing its financial assets and the contractual terms of the cash flows. There are three measurement categories into which the Company classified its financial assets:

- Amortized Cost: Includes assets that are held within a business model whose objective is to hold assets to collect contractual cash flows and its contractual terms give rise on specified dates to cash flows that represent solely payments of principal and interest;
- FVOCI: Includes assets that are held within a business model whose objective is achieved by both collecting contractual cash flows and selling the financial assets, where its contractual terms give rise on specified dates to cash flows that represent solely payments of principal and interest; or
- FVTPL: Includes assets that do not meet the criteria for amortized cost or FVOCI and are measured at fair value through profit or loss. This includes all derivative financial instruments.

On initial recognition, the Company may irrevocably designate a financial asset that meets the amortized cost or FVOCI criteria as measured at FVTPL if doing so eliminates or significantly reduces an accounting mismatch. On initial recognition of an equity investment that is not held-for-trading, the Company may irrevocably elect to present subsequent changes in the investment's fair value in OCI. There is no subsequent reclassification of fair value changes to earnings following the derecognition of the investment. However, dividends that reflect a return on investment continue to be recognized in net earnings. This election is made on an investment-by-investment basis.



At initial recognition, the Company measures a financial asset at its fair value and, in the case of a financial asset not at FVTPL, including transaction costs that are directly attributable to the acquisition of the financial asset. Transaction costs of financial assets carried at FVTPL are recorded as an expense in net earnings.

Financial assets are reclassified subsequent to their initial recognition only if the business model for managing those financial assets changes. The affected financial assets will be reclassified on the first day of the first reporting period following the change in the business model. A financial asset is derecognized when the rights to receive cash flows from the asset have expired or have been transferred and the Company has transferred substantially all the risks and rewards of ownership.

Impairment of Financial Assets

The Company recognizes loss allowances for ECLs on its financial assets measured at amortized cost. Due to the nature of its financial assets, the Company measures loss allowances at an amount equal to expected lifetime ECLs. Lifetime ECLs are the anticipated ECLs that result from all possible default events over the expected life of a financial asset. ECLs are a probability-weighted estimate of credit losses. Credit losses are measured as the present value of all cash shortfalls (i.e. the difference between the cash flows due to the entity in accordance with the contract and the cash flows that the Company expects to receive). ECLs are discounted at the effective interest rate of the related financial asset. The Company does not have any financial assets that contain a financing component.

Classification and Measurement of Financial Liabilities

A financial liability is initially classified as measured at amortized cost or FVTPL. A financial liability is classified as measured at FVTPL if it is held-for-trading, a derivative, or designated as FVTPL on initial recognition. The classification of a financial liability is irrevocable.

Financial liabilities at FVTPL are measured at fair value with changes in fair value, along with any interest expense, recognized in net earnings. Other financial liabilities are initially measured at fair value less directly attributable transaction costs and are subsequently measured at amortized cost using the effective interest method. Interest expense and foreign exchange gains and losses are recognized in net earnings. Any gain or loss on derecognition is also recognized in net earnings.

A financial liability is derecognized when the obligation is discharged, cancelled or expired. When an existing financial liability is replaced by another from the same counterparty with substantially different terms, or the terms of an existing liability are substantially modified, it is treated as a derecognition of the original liability and the recognition of a new liability. When the terms of an existing financial liability are altered, but the changes are considered non-substantial, it is accounted for as a modification to the existing financial liability. Where a liability is substantially modified it is considered to be extinguished and a gain or loss is recognized in net earnings based on the difference between the carrying amount of the liability derecognized and the fair value of the revised liability. Where a liability is modified in a non-substantial way, the amortized cost of the liability is remeasured based on the new cash flows and a gain or loss is recorded in net earnings.

Derivative Financial Instruments

Derivative financial instruments are used to manage economic exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Policies and procedures are in place with respect to required documentation and approvals for the use of derivative financial instruments. Where specific financial instruments are executed, the Company assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in the particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

Risk management assets and liabilities are derivative financial instruments classified as measured at FVTPL unless designated for hedge accounting. Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using mark-to-market accounting whereby instruments are recorded in the consolidated balance sheets as either an asset or liability with changes in fair value recognized in net earnings as a gain or loss on risk management. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third-party market indications and forecasts.

New Accounting Standards Not Yet Adopted

On January 13, 2016, the IASB issued IFRS 16, "Leases". The standard is required to be adopted either retrospectively or by recognizing the cumulative effect of initially applying IFRS 16 as an adjustment to opening equity at the date of initial application. IFRS 16 is effective for fiscal years beginning on or after January 1, 2019. Under the new standard, companies will recognize new assets and liabilities, bringing off-balance-sheet leasing arrangements onto the balance sheet. The Company intends to adopt IFRS 16 in its financial statements for the annual period beginning on January 1, 2019. Although the transition approach on adoption has not yet been determined, it is anticipated that the adoption of IFRS 16 will have a material impact on the Company's 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, 2017 consolidated financial statements for details concerning determination of fair values.

5. Accounts Receivable

	March 31, 2018	December 31, 2017
Trade receivables	\$ 25,956	\$ 28,366
Colombia income taxes receivable	47,133	36,843
Value added taxes (VAT)	14,634	13,943
	\$ 87,723	\$ 79,152

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 \$14.6 million as at March 31, 2018 (December 31, 2017 - \$13.9 million) and is recoverable in 2018. All accounts receivable are expected to be received within twelve months and are thus recognized as current assets.

6. Inventory

	March 31, 2018	December 31, 2017
Crude oil inventory	\$ 3,802	\$ 3,038

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

Cost	
Balance, December 31, 2016	\$ 101,024
Additions	71,066
Transfers to PP&E	(29,757)
Changes in decommissioning liability	432
Exploration and evaluation impairment	(35,621)
Balance, December 31, 2017	\$ 107,144
Additions	18,930
Balance, March 31, 2018	\$ 126,074

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 \$18.9 million for the three months ended March 31, 2018 represent the Company's share of costs incurred on E&E assets during the period. For the three months ended March 31, 2018, no E&E assets were transferred to PP&E.

During the year ended December 31, 2017, additions of \$71.1 million represent the Company's share of costs incurred on E&E assets during the period. \$29.8 million of E&E assets were transferred to PP&E mainly related to the Aguas Blancas Block during the year ended December 31, 2017. Also in 2017, the Company recorded \$35.6 million of impairment charges associated with VMM-11 in the Middle Magdalena basin.

At March 31, 2018 the Company did not have E&E assets in Canada.



8. Property, Plant and Equipment

	Canada	Colombia	Total
Cost			
Balance, December 31, 2016	\$ 3,733	\$ 1,614,123	\$ 1,617,856
Additions	47	135,536	135,583
Transfers from E&E assets	—	29,757	29,757
Additions related to property acquisition	—	9,994	9,994
Changes in decommissioning and environmental liability	—	(1,588)	(1,588)
Balance, December 31, 2017	\$ 3,780	\$ 1,787,822	\$ 1,791,602
Additions	2	39,278	39,280
Additions to decommissioning and environmental liability	—	2,257	2,257
Balance, March 31, 2018	\$ 3,782	\$ 1,829,357	\$ 1,833,139

Accumulated Depreciation, Depletion and Amortization

Balance, December 31, 2016	\$ 3,348	\$ 1,088,238	\$ 1,091,586
Depletion and depreciation for the year	185	98,553	98,738
DD&A included in crude oil inventory costing	—	(159)	(159)
Balance, December 31, 2017	\$ 3,533	\$ 1,186,632	\$ 1,190,165
Depletion and depreciation for the period	35	22,404	22,439
DD&A included in crude oil inventory costing	—	389	389
Balance, March 31, 2018	\$ 3,568	\$ 1,209,425	\$ 1,212,993

Net book value:

As at December 31, 2016	\$ 385	\$ 525,885	\$ 526,270
As at December 31, 2017	\$ 247	\$ 601,190	\$ 601,437
As at March 31, 2018	\$ 214	\$ 619,932	\$ 620,146

In the three months ended March 31, 2018 additions of \$39.3 million mainly relate to drilling costs in Colombia at Block LLA-34 and Cabrestero Block. For the three months ended March 31, 2018, no E&E assets were transferred to PP&E.

For the three months ended March 31, 2018 future development costs of \$389.4 million (three months ended March 31, 2017 - \$253.2 million) were included in the depletion calculation for development and production assets. For the three months ended March 31, 2018 \$2.4 million of general and administrative costs (three months ended March 31, 2017 - \$1.3 million) have been capitalized in respect of development and exploration activities during the current period.

During the year ended December 31, 2017, additions of \$135.6 million mainly related to drilling costs in Colombia at Block LLA-34, Cabrestero block, and the Aguas Blancas block. For the year ended December 31, 2017, \$29.8 million of E&E assets were transferred to PP&E mainly related to the Aguas Blancas block. Also in 2017, the Company recorded \$10.0 million of additions related to property acquisitions as described in Note 9 of the consolidated financial statements for the year ended December 31, 2017.

9. Revenue

The Company's oil and natural gas production revenue is determined pursuant to the terms of the revenue agreements. The transaction price for crude oil and natural gas is based on the commodity price in the month of production, adjusted for quality, location, allowable deductions, if any, or other factors. Commodity prices are based on market indices that are determined on a monthly or daily basis.



The Company's oil and natural gas revenues by product are as follows:

For the three months ended March 31, (000s)	2018		2017	
Crude oil	\$	200,496	\$	129,086
Natural gas		1,954		993
	\$	202,450	\$	130,079

At March 31, 2018, receivables from contracts with customers, which are included in accounts receivable, were \$26.0 million (March 31, 2017 - \$31.8 million).

10. Net Finance Expense (Income)

For the three months ended March 31, (000s)	2018		2017	
Bank taxes and credit facility fees	\$	420	\$	909
Accretion on decommissioning and environmental liabilities		1,220		835
Interest and other income		(545)		(384)
Colombian net wealth tax		—		894
Net finance expense	\$	1,095	\$	2,254

For the three months ended March 31, (000s)	2018		2017	
Non-cash finance expense	\$	1,220	\$	835
Cash finance (income) expense		(125)		1,419
Net finance expense	\$	1,095	\$	2,254

11. Other Long-Term Liabilities

Other long-term liabilities are comprised of the following:

	March 31, 2018		December 31, 2017	
Long-term SARs payable	\$	1,321	\$	1,250
Long-term DSUs payable		2,468		2,474
Long-term CRSUs payable		1,692		994
	\$	5,481	\$	4,718

12. Decommissioning and Environmental Liabilities

	Decommissioning		Environmental		Total
Balance, December 31, 2016	\$	38,720	\$	12,426	\$ 51,146
Additions		5,313		2,223	7,536
Settlements of obligations during the year		(954)		(437)	(1,391)
Accretion expense		2,549		1,416	3,965
Additions related to change in estimate - inflation and discount rates		(9,773)		(1,809)	(11,582)
Additions related to change in estimate - costs		391		2,499	2,890
Foreign exchange loss (gain)		528		(412)	116
Balance, December 31, 2017	\$	36,774	\$	15,906	\$ 52,680
Additions		1,419		838	2,257
Settlements of obligations during the period		(835)		(40)	(875)
Accretion expense		627		593	1,220
Foreign exchange loss		2,719		1,067	3,786
Balance, March 31, 2018	\$	40,704	\$	18,364	\$ 59,068
Current obligation		(3,470)		(6,162)	(9,632)
Long-term obligation	\$	37,234	\$	12,202	\$ 49,436



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 March 31, 2018, 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 \$72.7 million as at March 31, 2018 (December 31, 2017 – \$66.4 million) with the majority of these costs anticipated to occur in 2021 or later. 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, 2017 – 7.5 percent risk-free discount rate and a 4.0 percent inflation rate). The risk-free discount rate and the inflation rate used are based on forecast Colombia rates.

Included in the decommissioning liability is \$3.5 million (December 31, 2017 – \$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 \$23.5 million as at March 31, 2018 (December 31, 2017 – \$19.0 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, 2017 – 7.5 percent risk-free discount rate and a 4.0 percent inflation rate). The risk-free discount rate and the inflation rate used are based on forecast Colombia rates.

Included in the environmental liability is \$6.2 million (December 31, 2017 – \$5.6 million) that is classified as a current obligation.

13. Share Capital

a) Issued and outstanding common shares

	Number of shares	Amount (\$000s)
Balance, December 31, 2016	152,990,495	\$ 822,227
Issued for cash – exercise of options and RSUs	2,328,239	9,906
Allocation of contributed surplus – exercise of options and RSUs	—	6,762
Repurchase of shares	(576,600)	(2,729)
Balance, December 31, 2017	154,742,134	\$ 836,166
Issued for cash – exercise of options and RSUs	1,693,539	8,298
Allocation of contributed surplus – exercise of options and RSUs	—	4,730
Repurchase of shares	(789,120)	(3,673)
Balance, March 31, 2018	155,646,553	\$ 845,521

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

In the three months ended March 31, 2018, a total of 1,693,539 options and RSUs were exercised for proceeds of \$8.3 million (year ended December 31, 2017 - 2,328,239 options and RSUs were exercised for \$9.9 million).

In the three months ended March 31, 2018, the Company repurchased 789,120 common shares pursuant to its Normal Course Issuer Bid at a cost of \$11.2 million (average cost per share of Cdn\$18.18). In 2017, the Company repurchased 576,600 common shares pursuant to its Normal Course Issuer Bid at a cost of \$7.5 million (average cost per share of Cdn\$16.39). 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 9 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 options	Weighted average exercise price Cdn\$/option
Balance, December 31, 2016	7,741,774	9.68
Granted	666,500	15.88
Exercised	(1,884,422)	6.84
Forfeited	(44,417)	12.82
Balance, December 31, 2017	6,479,435	11.13
Granted	194,650	18.52
Exercised	(1,501,202)	7.05
Balance, March 31, 2018	5,172,883	12.59

Stock options outstanding and the weighted average remaining life of the stock options at March 31, 2018 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
\$6.07 - \$10.59	1,391,371	1.41	9.37	1,391,371	1.41	9.37
\$10.60 - \$11.24	1,623,835	2.61	10.94	1,019,323	2.61	10.94
\$11.25 - \$15.59	134,942	3.10	13.75	41,458	1.33	12.42
\$15.60 - \$15.84	1,240,401	3.62	15.66	391,889	3.62	15.66
\$15.85 - \$18.53	782,334	4.16	16.66	193,277	3.93	16.05
	5,172,883	2.78	12.59	3,037,318	2.26	11.17

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 three months ended March 31,	2018	2017
Risk-free interest rate (%)	1.93	1.09
Expected life (years)	4	4
Expected volatility (%)	43	44
Forfeiture rate (%)	3	3
Expected dividends	—	—

The weighted average fair value at the grant date for the three months ended March 31, 2018 was Cdn\$6.68 per option (three months ended March 31, 2017 - Cdn\$5.65 per option). The weighted average share price on the exercise date for options exercised in the three months ended March 31, 2018 was Cdn\$18.43 (three months ended March 31, 2017 - Cdn\$16.11).

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, 2016	2,588,146	0.01
Granted	632,550	0.01
Exercised	(443,817)	0.01
Forfeited	(46,584)	0.01
Balance, December 31, 2017	2,730,295	0.01
Granted	516,625	0.01
Exercised	(192,337)	0.01
Balance, March 31, 2018	3,054,583	0.01



RSUs outstanding and the weighted average remaining life of the RSUs at March 31, 2018 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	3,054,583	3.25	1,348,469	2.43

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 three months ended March 31, 2018 was Cdn\$18.51 per RSU (three months ended March 31, 2017 - Cdn\$15.98 per RSU). For the three months ended March 31, 2018 a weighted average forfeiture rate of 3% was applied (three months ended March 31, 2017 - 3%).

Pursuant to the 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. PSUs 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.

	Number of PSU's	Weighted average exercise price Cdn\$/PSU
Balance at December 31, 2016	—	—
Granted	103,500	0.01
Balance, December 31, 2017	103,500	0.01
Granted	217,000	0.01
Balance, March 31, 2018	320,500	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 three months ended March 31, 2018 was Cdn\$18.52 per PSU (three months ended March 31, 2017 - Cdn\$16.01 per PSU).

d) Share-based compensation expense

For the three months ended March 31,	2018		2017	
Option expense	\$	959	\$	1,957
Restricted share units including performance share units expense		2,554		2,769
Total	\$	3,513	\$	4,726

14. 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, 2016	3,806,237	11.91
Granted	134,086	16.39
Exercised	(1,323,125)	9.67
Forfeited	(229,191)	12.20
Balance, December 31, 2017	2,388,007	13.38
Exercised	(348,942)	12.15
Forfeited	(14,928)	13.70
Balance, March 31, 2018	2,024,137	13.59

As at March 31, 2018, 592,469 SARs were vested (December 31, 2017 - 873,208).



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 three months ended March 31,	2018	2017
Risk-free interest rate (%)	1.72	0.88
Expected life (years)	2	4
Expected volatility (%)	36	46
Share price (\$/Cdn)	18.12	16.95
Expected dividends	—	—

As at March 31, 2018, the total SARs liability accrued is \$9.5 million (December 31, 2017 - \$11.6 million) of which \$1.3 million (December 31, 2017 - \$1.2 million) is classified as long-term in accordance with the three year vesting period. For the three months ended March 31, 2018, Parex recorded \$0.8 million recovery of compensation costs related to the outstanding SARs (year ended December 31, 2017 - \$4.7 million expense).

b) Deferred share units

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 retirement from the Board of Directors of 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, 2016	145,900	—
Granted	65,075	—
Exercised on board retirement	(17,000)	—
Balance, December 31, 2017	193,975	—
Exercised on board retirement	(23,100)	—
Balance, March 31, 2018	170,875	—

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. There were no DSUs granted during the three months ended March 31, 2018 (weighted average fair value at the grant date for the year ended December 31, 2017 - Cdn\$16.67 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 March 31, 2018 the total DSUs liability accrued is \$2.5 million (December 31, 2017 - \$2.8 million) and is classified as long-term in accordance with the terms of the DSU plan (December 31, 2017 - \$2.5 million classified as long-term).

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	504,020	—
Forfeited	(11,670)	—
Balance, December 31, 2017	492,350	—
Granted	472,675	—
Forfeited	(4,350)	—
Balance, March 31, 2018	960,675	—

As at March 31, 2018, no CRSUs were fully 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 March 31, 2018, the total CRSUs liability accrued is \$3.7 million (December 31, 2017 - \$2.2 million) of which \$1.7 million (December 31, 2017 - \$1.0 million) is classified as long-term in accordance with the three year vesting period. For the three months ended March 31, 2018, Parex recorded \$1.5 million of compensation costs related to the outstanding CRSUs (year ended December 31, 2017 - \$2.2 million expense).

d) Cash settled share-based compensation

For the year ended December 31,

	2018	2017
SARs expense	\$ (750)	1,803
CRSUs expense	1,534	—
DSUs expense	(13)	—
Total	\$ 771	\$ 1,803

15. Income Tax

The components of tax expense for the three months ended March 31, 2018 and 2017 were as follows:

For the three months ended March 31,	2018	2017
Current tax expense	\$ 27,280	\$ 4,857
Deferred tax expense (recovery)	550	(1,277)
Total tax expense	\$ 27,830	\$ 3,580

16. Net income per Share

a) Basic net income per share

For the three months ended March 31	2018	2017
Net income		
Net income for the purpose of basic net income per share	\$ 71,512	\$ 40,106
Weighted average number of shares for the purposes of basic net income per share (000's)	155,037	153,284
Basic net income per share	0.46	0.26

b) Diluted net income per share

For the three months ended March 31	2018	2017
Net income		
Net income used to calculate diluted net income per share	\$ 71,512	\$ 40,106
Weighted average number of shares for the purposes of basic net income per share (000's)	155,037	153,284
Dilutive effect of share options and RSUs on potential common shares	3,053	3,418
Weighted average number of shares for the purposes of diluted net income per share	158,090	156,702
Diluted net income per share	0.45	0.26

At March 31, 2018, 193,650 (December 31, 2017 - 593,100) share options had an exercise price in excess of the average market value of the shares from the option grant date to the end of the period. As a result, these share options are excluded from the calculation of diluted earnings per share.



17. Supplemental Disclosure of Cash Flow Information

a) Net change in non-cash working capital

For the three months ended March 31,	2018	2017
Accounts receivable	\$ (8,571)	\$ (20,409)
Prepays and other current assets	(2,055)	184
Oil inventory	(764)	2,744
Accounts payable and accrued liabilities	30,291	18,244
Depletion related to oil inventory	389	(745)
Net change in non-cash working capital	\$ 19,290	\$ 18
Operating	\$ 11,792	\$ (14,535)
Investing	7,498	14,553
Financing	-	-
Net change in non-cash working capital	\$ 19,290	\$ 18

b) Interest and taxes paid

For the three months ended March 31,	2018	2017
Cash interest paid	\$ 1	\$ 20
Cash income and equity taxes paid	\$ 310	\$ —

18. 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.

Parx has a senior secured credit facility which as at March 31, 2018 had a borrowing base in the amount of \$100.0 million. The credit facility is intended to serve as means to increase liquidity and fund cash needs as they arise. As at March 31, 2018, \$nil (December 31, 2017 - \$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, 2017 - limit of \$250.0 million) of which \$99.6 million (December 31, 2017 - \$116.1 million) is utilized at March 31, 2018. At March 31, 2018, there is an additional \$26.4 million (December 31, 2017 - \$26.4 million) of letters of credit that are provided by a Latin American bank on an unsecured basis.

As at March 31, 2018, the Company's net working capital surplus was \$205.8 million (December 31, 2017 - \$163.4 million), of which \$294.5 million is cash.

Parx 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 March 31, 2018 shareholders' equity was \$960.4 million (December 31, 2017 - \$888.3 million).

19. 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 three months ended March 31, 2018 had the majority of its oil sales to 10 counterparties. Accounts receivable balance as at March 31, 2018 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 March 31, 2018, there were no accounts receivable past due (December 31, 2017 - \$nil).

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 March 31, 2018 was \$nil.

The following are the contractual maturities of financial liabilities at March 31, 2018:

	Less than 1 year	2-3 Years	4-5 Years	Thereafter	Total
Accounts payable and accrued liabilities ⁽¹⁾	\$ 91,968	—	—	—	\$ 91,968
Cash settled equity plans payable	10,209	5,481	—	—	15,690
Total	\$ 102,177	5,481	—	—	\$ 107,658

⁽¹⁾Includes the liability for derivative financial instruments.

The following are the contractual maturities of financial liabilities at December 31, 2017:

	Less than 1 year	2-3 Years	4-5 Years	Thereafter	Total
Accounts payable and accrued liabilities ⁽¹⁾	\$ 91,736	—	—	—	\$ 91,736
Cash settled equity plans payable	11,889	4,718	—	—	16,607
Total	\$ 103,625	4,718	—	—	\$ 108,343

⁽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 March 31, 2018, 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 three months ended March 31, 2018:

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
January 1, 2018 to June 30, 2018	ICE Brent	5,000	\$ 47.00	\$ 50.00	—	\$ 0.27
April 1, 2018 to September 30, 2018	ICE Brent	10,000	\$ 50.00	\$ 55.00	—	\$ 0.40

The fair value of the ICE Brent priced crude oil risk management contracts at March 31, 2018 is a \$0.4 million payable (December 31, 2017 – payable of \$0.1 million) and is recorded in the financial statement line item "Derivative financial instruments" in the consolidated balance sheet.



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

For the three months ended March 31,	2018	2017
Premiums paid on commodity risk management contracts	180	1,189
Unrealized (gain) loss on commodity risk management contracts	216	(2,507)
Total	\$ 396	\$ (1,318)

There are no unamortized premiums at March 31, 2018 or December 31, 2017.

As shown in the table above, as at March 31, 2018, Parex had committed to the future sale of 2,285,000 barrels of oil with put spreads from Brent oil prices of \$47.00 to \$55.00 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 March 31, 2018:

	Brent Price	Impact for the three months ended March 31, 2018	
		Increase of \$10/bbl	Decrease of \$10/bbl
Oil hedged contract total	Period end \$	278	\$ (1,206)

20. Segmented Information

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

For the three months ended March 31, 2018

	Canada	Colombia	Total
Oil sales	\$ —	\$ 202,450	\$ 202,450
Royalties	—	(26,179)	(26,179)
Revenue	—	176,271	176,271
Risk management contracts (loss)	—	(396)	(396)
Expenses		175,875	175,875
Production	—	19,202	19,202
Transportation	—	15,343	15,343
Purchased oil	—	1,436	1,436
General and administrative	2,949	5,206	8,155
Share-based compensation equity settled	3,513	—	3,513
Share-based compensation cash settled	(13)	784	771
Depletion, depreciation and amortization	35	22,404	22,439
Foreign exchange loss (gain)	(27)	4,606	4,579
	6,457	68,981	75,438
Finance (income)	(179)	(366)	(545)
Finance expense	141	1,499	1,640
Net finance expense	(38)	1,133	1,095
Net income (loss) before taxes	(6,419)	105,761	99,342
Current tax expense	—	27,280	27,280
Deferred tax expense	—	550	550
Net income (loss)	\$ (6,419)	\$ 77,931	\$ 71,512
Capital assets (end of period)	\$ 214	\$ 746,006	\$ 746,220
Capital expenditures	\$ 2	\$ 58,208	\$ 58,210
Total assets (end of period)	\$ 75,365	\$ 1,154,532	\$ 1,229,897



For the three months ended March 31, 2017

	Canada	Colombia	Total
Oil sales	\$ —	\$ 130,079	\$ 130,079
Royalties	—	(13,252)	(13,252)
Revenue	—	116,827	116,827
Risk management contracts gain	—	1,318	1,318
	—	118,145	118,145
Expenses			
Production	—	15,389	15,389
Transportation	—	14,180	14,180
Purchased oil	—	2,374	2,374
General and administrative	2,852	4,888	7,740
Share-based compensation equity settled	4,726	—	4,726
Share-based compensation cash settled	—	1,803	1,803
Depletion, depreciation and amortization	46	24,363	24,409
Foreign exchange loss	81	1,503	1,584
	7,705	64,500	72,205
Finance (income)	(142)	(242)	(384)
Finance expense	305	2,333	2,638
Net finance expense	163	2,091	2,254
Net income (loss) before taxes	(7,868)	51,554	43,686
Current tax expense	—	4,857	4,857
Deferred tax (recovery)	—	(1,277)	(1,277)
Net income (loss)	\$ (7,868)	\$ 47,974	\$ 40,106
Capital assets (end of period)	\$ 363	\$ 640,592	\$ 640,955
Capital expenditures	\$ 24	\$ 35,539	\$ 35,563
Total assets (end of period)	\$ 88,095	\$ 896,760	\$ 984,855

In Colombia the majority of oil sales are with 10 customers in the oil and gas industry and are subject to normal industry credit risks.

21. Commitments

a) Colombia

At March 31, 2018, performance guarantees are in place with Ecopetrol for the Capachos and Aguas Blancas farm-in blocks and the ANH for all other blocks. The guarantees are in the form of issued letters of credit totaling \$126.0 million (December 31, 2017 - \$142.6 million) to support the exploration work commitments in respect of the 20 blocks in Colombia.

At March 31, 2018, EDC has provided the Company's bank with performance security guarantees to support approximately \$99.6 million (December 31, 2017 - \$116.1 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. At March 31, 2018, there are an additional \$26.4 million (December 31, 2017 - \$26.4 million) letters of credit that are provided by a Latin American bank on an unsecured basis.

The value of the Company's exploration commitments as at March 31, 2018 in respect of the Colombia blocks are estimated to be as follows:

2018	\$	129,789
2019		24,218
Thereafter		—
	\$	154,007



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 March 31, 2018 are as follows:

	Total	2018	2019	2020	2021	2022	Thereafter
Office and accommodations	\$ 7,001	1,482	979	1,243	963	763	1,571

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 three months ended March 31, 2018 is dated May 8, 2018 and should be read in conjunction with the Company's unaudited condensed interim consolidated financial statements for the three months ended March 31, 2018, as well as the Company's audited consolidated annual financial statements for the year ended December 31, 2017. 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 5, 2018 ("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 1,574,279 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 16 for the Advisory on Forward-Looking Statements and page 17 for Non-GAAP Terms used.

Three months ended March 31, 2018 ("first quarter or Q1") Highlights

- Quarterly production was 40,586 boe/d (99% crude oil), representing an increase of 4 percent over the previous quarter ended December 31, 2017 and an increase of 25 percent over the three months ended March 31, 2017;
- Earned net income of \$71.5 million (\$0.46 per share basic) compared to the three months ended March 31, 2017 where a net income of \$40.1 million (\$0.26 per share basic) was recorded;
- Generated funds flow from operations of \$100.9 million (\$0.65 per share basic as compared to \$0.44 per share for the three months ended March 31, 2017). Funds flow has increased from the comparative 2017 period due to an increase in oil prices and increased production volumes;
- Capital expenditures were \$58.2 million in the period compared to \$35.6 million in the three months ended March 31, 2017. Parex expects to invest \$260 - \$290 million in capital projects in 2018. It is expected that activity levels will increase significantly in the second and third quarters of 2018;
- Working capital increased to \$205.8 million at March 31, 2018 compared to \$163.4 million at December 31, 2017 mainly as a result of free funds flow of \$42.7 million in the quarter. Bank debt continues to be \$nil;
- Repurchased 789,120 common shares pursuant to the Normal Course Issuer Bid at a cost of \$11.2 million (average cost per share of Cdn\$18.18); and
- Participated in drilling 12 gross wells in Colombia resulting in 8 oil wells, 1 disposal well, 2 abandoned wells and 1 under test, for a success rate of 80 percent.

Financial Summary

For the three months ended March 31 (Financial figures in 000s except per share amounts)	2018	2017
Average daily oil production (bbl/d)	40,063	32,317
Average daily natural gas production (mcf/d)	3,138	1,644
Average oil and natural gas production (boe/d)	40,586	32,591
Production split (% crude oil)	99	99
Average realized sales price (\$/boe) ⁽¹⁾	\$ 55.98	\$ 42.21
Operating netback (\$/boe) ⁽²⁾	\$ 39.10	\$ 28.14
Oil and natural gas sales (including purchased oil sales) ⁽¹⁾	\$ 202,450	\$ 130,079
Funds flow provided by operations	\$ 100,901	\$ 67,906
Per share – basic	\$ 0.65	\$ 0.44
Per share – diluted ⁽²⁾	\$ 0.64	\$ 0.43
Net income	\$ 71,512	\$ 40,106
Per share – basic	\$ 0.46	\$ 0.26
Per share – diluted	\$ 0.45	\$ 0.26
Capital expenditures	\$ 58,210	\$ 35,563
Total assets (end of period)	\$ 1,229,897	\$ 984,855
Working capital (end of period) ⁽³⁾	\$ 205,771	\$ 131,056
Bank debt (end of period) ⁽⁴⁾	-	-
Weighted average shares outstanding (000s)		
Basic	155,037	153,284
Diluted	158,090	156,702
Outstanding shares (end of period) (000s)	155,647	153,714

(1) In Q1 2018 the Company changed its accounting policy regarding revenue and transportation costs on certain oil sale contracts. The change has no impact on operating netback, cash flow or net income. For further information refer to the 'Impact of Accounting Policy Change' section on page 5.

(2) Non-GAAP terms. See "Non-GAAP Terms" on page 17.

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

(4) Syndicated bank credit facility borrowing base of \$100.0 million as at March 31, 2018 (March 31, 2017 - \$175.0 million).

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 surface, subsurface and commercial risks.



Principal Properties

As at March 31, 2018, the Company's principal land holdings and interests in exploration blocks held by its subsidiaries were as follows:

	Working Interest	Gross Acres	Net Acres
Colombia Llanos Basin			
<u>Operated Properties</u>			
LLA-16, 29 and 30	100 %	197,294	197,294
Los Ocarros	100 %	31,066	31,066
Cabrestero	100 %	7,605	7,605
LLA-40	100 %	82,422	82,422
LLA-26	100 %	93,376	93,376
Capachos ⁽¹⁾	50 %	64,073	32,037
LLA-32	87.5 %	57,040	49,910
LLA-10 ⁽¹⁾	50 %	189,544	94,772
<u>Non-Operated Properties</u>			
LLA-34	55 %	68,382	37,610
Balay	10 %	4,500	450
Colombia Magdalena Basin			
<u>Operated Properties</u>			
VMM-11 ⁽²⁾	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 ⁽¹⁾	100 %	3,695	3,695
Total		1,574,279	1,290,033

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

(2) The Company plans to relinquish VMM-11 land in 2018.

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.

2018 Guidance

Parex' guidance for 2018, as previously press released on November 7, 2017 is as follows:

Annual production (boe/d, 99% oil)	41,000-43,000
Capital Expenditures (millions)	
Maintenance (14 gross wells and related facilities)	\$90
Growth Capital (30-36 gross wells and related facilities)	\$170-200
Total (millions)	\$260-\$290

Based on 2018 results to date and the growth opportunities the Company has identified, it is expected that both annual production and capital expenditures will be at the high end of the guidance ranges. Planned capital expenditures are expected to be fully funded by funds flow from operations, with working capital being retained for future opportunities and to buy back outstanding shares as deemed appropriate.



Financial and Operational Results

Consolidated Results of Operations

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

For the three months ended March 31,	2018	2017
Average daily production		
Colombia – oil (bbl/d)	40,063	32,317
Colombia – natural gas (mcf/d)	3,138	1,644
Total (boe/d)	40,586	32,591
Production split (% crude oil production)	99	99
Average daily sales of oil and natural gas		
Colombia – produced and drawn oil inventory (bbl/d)	39,378	33,308
Colombia – purchased oil (bbl/d)	285	657
Colombia – produced natural gas (Mcf/d)	3,138	1,644
Total (boe/d)	40,186	34,239
Operating netback (000s) ⁽¹⁾		
Oil and natural gas sales ⁽²⁾	202,450	130,079
Royalties	(26,179)	(13,252)
Net revenue	176,271	116,827
Production expense	(19,202)	(15,389)
Transportation expense ⁽²⁾	(15,343)	(14,180)
Purchased oil expense	(1,436)	(2,374)
Operating netback	140,290	84,884
Operating netback (per boe) ⁽¹⁾		
Oil and natural gas sales ⁽²⁾	55.98	42.21
Royalties	(7.29)	(4.38)
Net revenue	48.69	37.83
Production expense	(5.35)	(5.09)
Transportation expense ⁽²⁾	(4.24)	(4.60)
Operating netback	39.10	28.14

(1) Non-GAAP terms. See "Non-GAAP Terms" on page 17.

(2) In Q1 2018 the Company changed its accounting policy regarding revenue and transportation costs on certain oil sale contracts. The change has no impact on operating netback, cash flow or net income. For further information refer to the 'Impact of Accounting Policy Change' section on page 5.

The average realized sales price for the three months ended March 31, 2018 was \$55.98/boe (\$42.21/boe - three months ended March 31, 2017) compared to \$50.43/boe for the fourth quarter of 2017.

Royalty charges for the three months ended March 31, 2018 were \$7.29/boe (\$4.38/boe - three months ended March 31, 2017) compared to \$5.58/boe for the fourth quarter of 2017.

Production expense for the three months ended March 31, 2018 was \$5.35/boe (\$5.09/boe - three months ended March 31, 2017) compared to \$5.41/boe for the fourth quarter of 2017.

Transportation expense for the three months ended March 31, 2018 was \$4.24/boe (\$4.60/boe - three months ended March 31, 2017) compared to \$4.05/boe for the fourth quarter of 2017.

The Company's operating netback on a per boe basis for the three months ended March 31, 2018 was \$39.10/boe (\$28.14/boe - three months ended March 31, 2017) compared to \$35.39/boe for the fourth quarter of 2017.



Overall the price of the Company's benchmark Brent crude increased by \$5.81/boe in the first quarter of 2018 as compared to the fourth quarter of 2017 while the operating netback increased by \$3.71/boe in the same period. The difference is mainly a result of increased royalties as a result of higher crude reference prices.

Colombian Oil and Natural Gas Sales

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

For the three months ended March 31,	2018	2017
Block LLA-34 (Tigana, Jacana, Tua, Tarotaro & Tilo fields)	30,781	22,406
Block LLA-26 (Rumba field)	2,248	3,845
Block Cabrestero (Bacano & Akira fields)	4,168	2,515
Block LLA-32 (Kananaskis, Calona & Carmentea fields)	1,017	1,012
Other	1,849	2,539
Total Crude Oil Production	40,063	32,317
Natural gas production	523	274
Total crude oil and natural gas production	40,586	32,591
Crude oil inventory (build) draw	(685)	991
Average daily sales of produced oil and natural gas	39,901	33,582
Purchased oil	285	657
Sales Volumes	40,186	34,239

Oil and natural gas production for the first quarter of the year averaged 40,586 boe/d, an increase of approximately 25 percent from the first quarter of 2017, and an increase of approximately 4 percent over the fourth quarter of 2017. Oil sales in the first quarter of 2018 increased to 40,186 boe/d compared to the reported Colombian oil sales of 34,239 boe/d for the three months ended March 31, 2017. The increase in oil sales was primarily due to an increase in oil production over the comparative period.

b) Impact of Accounting Policy Change

On January 1st, 2018 Parex adopted a new accounting policy that changed to the way the Company records revenue and transportation costs on certain oil sale contracts. The change resulted in a decrease in revenue and a corresponding decrease in transportation expense. There is no impact on cash flows, net income or overall operating netback. Below is a summary detailing the impact of the change for the first quarter of 2018 as well as the impact of the change on the comparative three months ended March 31, 2017:

For the three months ended March 31,	Q1 2018	Upon accounting policy change	As previously released
		Q1 2017	Q1 2017
Realized price differential to Brent (\$/boe)	(11.29)	(12.40)	(5.89)
Transportation expense (\$/boe)	(4.24)	(4.60)	(11.11)
Total differential plus transportation expense (\$/boe)	(15.53)	(17.00)	(17.00)

Note there is no overall impact to the total differential plus transportation expense only a change in the allocation between the two components. The realized price differential and transport costs may change quarter to quarter depending on the mix of crude marketing contract types.

c) Average Crude Oil Reference and Realized Prices

For the three months ended March 31,	2018	2017
Reference Prices		
Brent (\$/bbl)	67.27	54.61
Vasconia (\$/bbl)	62.87	49.57
WTI (\$/bbl)	62.89	51.77
Average Realized Prices		
Realized oil sales price (\$/bbl) ⁽¹⁾	56.17	42.21
Realized oil hedging (loss) gain (\$/bbl)	(0.06)	(0.39)
Realized price after hedging (\$/bbl)	56.11	41.82
Realized price differential to Brent crude (\$/bbl)	(11.10)	(12.40)

(1) In Q1 2018 the Company changed its accounting policy regarding revenue and transportation costs on certain oil sale contracts. The change has no impact on operating netback, cash flow or net income. For further information refer to the 'Impact of Accounting Policy Change' section on page 5.



The table below provides a quarter-by-quarter view of Parex' historical pricing in Colombia:

Average price for the period	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017
Brent (\$/bbl)	67.27	61.46	52.17	50.87	54.61
Vasconia (\$/bbl)	62.87	57.30	49.15	47.10	49.57
Vasconia (\$/bbl) differential	(4.40)	(4.16)	(3.02)	(3.77)	(5.04)
Parex quality differential (\$/bbl)	(0.24)	(0.40)	(1.08)	(0.26)	(0.85)
Parex adjustment on certain oil sale contracts (\$/bbl) ⁽¹⁾	(6.46)	(6.47)	(6.91)	(6.58)	(6.51)
Parex realized oil sales price (\$/bbl)	56.17	50.43	41.16	40.26	42.21
Parex realized price (differential) to Brent crude (\$/bbl)	(11.10)	(11.03)	(11.01)	(10.61)	(12.40)
Parex realized price (differential) to Vasconia crude (\$/bbl)	(6.70)	(6.87)	(7.99)	(6.84)	(7.36)

(1) The discount shown reflects the impact of the retrospectively applied accounting policy change. Effectively a corresponding decrease in transportation costs offsets this discount for a \$nil effect on operating netback, net income and funds flow from operations, refer to "Impact of Accounting Policy Change" on page 5.

d) Natural Gas Revenue and Realized Prices

For the three months ended March 31,		2018		2017
Revenue (000's)		\$ 1,954	\$	993
Realized sales price (\$/Mcf)		\$ 6.92	\$	6.71

e) Oil and Natural Gas Revenue

First quarter 2018 oil and natural gas revenue increased \$72.4 million or 56 percent as reconciled in the table below to the first quarter of 2017:

(000s)		
Oil and natural gas revenue, three months ended March 31, 2017		\$ 130,079
Sales volume of produced oil, an increase of 24% (7,746 bbl/d)		29,426
Sales volume of purchased oil, a decrease of 57% (372 bbl/d)		(1,413)
Oil and natural gas sales price increase of 32%		43,397
Sales volume and price change of produced natural gas, an increase of 97% (249 boe/d)		961
Oil and natural gas revenue, three months ended March 31, 2018		\$ 202,450

Oil and natural gas revenue increased in the three months ended March 31, 2018 compared to the same period in 2017 mainly due to a 32% increase in sales prices per boe and a 24% increase in produced oil volumes sold.

f) Crude Oil Inventory in Transit

For the three months ended March 31,		2018		2017
(000s)				
Crude oil in transit		\$ 3,802	\$	90

As at March 31, 2018, the Company had 164.8 mbbbls of crude oil inventory in transit (3.1 mbbbls of crude oil inventory in transit for the first quarter of 2017). The change from the prior period ended December 31, 2017 was an increase of 61,800 bbls which the Company expects will be drawn down by June 30, 2018.

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

For the periods ended (mbbls)	March 31, 2018	Dec. 31, 2017	Sept. 30, 2017	June 30, 2017
Crude oil inventory in transit - beginning of the period	103.0	70.9	44.1	3.1
Oil production	3,605.7	3,546.8	3,301.7	3,095.1
Oil sales	(3,569.7)	(3,542.2)	(3,298.8)	(3,079.1)
Purchased oil	25.8	27.5	23.9	25.0
Crude oil inventory in transit - end of the period	164.8	103.0	70.9	44.1
% of period production	4.6	2.9	2.1	1.4



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

g) Purchased Oil

For the three months ended March 31,	2018		2017	
Purchased oil expense (000s)	\$	1,436	\$	2,374

Purchased oil expense for the three months ended March 31, 2018 was \$1.4 million compared to \$2.4 million for the three months ended March 31, 2017 and \$1.4 million for the fourth quarter of 2017. Transportation costs are incurred by the Company to transport purchased oil to sale delivery points.

Royalties

For the three months ended March 31,	2018		2017	
Royalties (000s)	\$	26,179	\$	13,252
Per unit (\$/boe)		7.29		4.38
Percentage of oil and natural gas sales ⁽¹⁾⁽²⁾		13.0%		10.2%

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

(2) In Q1 2018 the Company changed its accounting policy regarding revenue and transportation costs on certain oil sale contracts. As a result of this, royalties as a percentage of sales have been changed. The change has no impact on operating netback, cash flow or net income. For further information refer to the 'Impact of Accounting Policy Change' section on page 5.

In the three months ended March 31, 2018 royalties as a percentage of sales was 13.0% as compared to 10.2% in the three months ended March 31, 2017. The increase in royalties as a percentage of sales 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. In the prior comparative period this minimum was not reached and therefore the HPR was not applicable. The HPR is applicable on the following oil fields, Tua, Tigana, Jacana, Las Maracas, and Kona.

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.

Production Expense

For the three months ended March 31,	2018		2017	
Production expense (000s)	\$	19,202	\$	15,389
Per unit (\$/boe)		5.35		5.09

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 March 31,	2018		2017	
Per unit (\$/boe) – based on sales volumes – operated ⁽¹⁾		9.37		7.96
Per unit (\$/boe) – based on sales volumes – non-operated ⁽¹⁾		4.10		3.91

(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 months ended March 31, 2018 was \$5.35/boe compared to \$5.09/boe for the three months ended March 31, 2017 and \$5.41/boe for the fourth quarter of 2017.

Operated properties production expense in the first quarter of 2018 was \$9.37/boe compared to \$7.96/boe for the three months ended the March 31, 2017 and \$8.84/boe for the fourth quarter of 2017. The increase in operated production expense per boe from the comparative periods is a result of an increase in well services performed on operated blocks, increased water handling and an increase in Colombian/USD exchange rates.

Non-operated properties production expense was \$4.10/boe for the first quarter of 2018 compared to \$3.91/boe for the three months ended March 31, 2017 and \$4.14/boe for the fourth quarter of 2017. The slight increase in non-operated production expense from the three months ended March 31, 2017 is a result of increased well services and an increase in Colombian/USD exchange rates.



Transportation Expense

For the three months ended March 31,		2018		2017
Transportation expense (000s) ⁽¹⁾	\$	15,343	\$	14,180
Per unit (\$/boe) ⁽¹⁾		4.24		4.60

(1) As a result of an accounting policy change the Company has changed prior period transportation expense on a gross dollar and per boe basis. Due to this transportation costs have decreased from previous quarter disclosure of \$10-11/boe to \$4-5/boe. Offsetting this decrease, realized sales prices have decreased by the same amount. The change has no effect on operating netback, net income, or funds flow from operations. For further information refer to the 'Impact of Accounting Policy Change' section on page 5.

For the three months ended March 31, 2018, the cost of transportation of \$4.24/boe has increased compared to the fourth quarter 2017 cost of \$4.05/boe and decreased from the three months ended March 31, 2017 of \$4.60/boe. The decrease from the three months ended March 31, 2017 is a result of a decrease in pipeline costs.

General and Administrative Expense ("G&A")

For the three months ended March 31, (000s)		2018		2017
Gross G&A	\$	10,649	\$	9,120
G&A recoveries		(86)		(129)
Capitalized G&A		(2,408)		(1,251)
Net G&A expense	\$	8,155	\$	7,740
Per unit (\$/boe) ⁽¹⁾		2.23		2.64

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

Net G&A was \$8.2 million for the three months ended March 31, 2018 compared to \$7.7 million for the same period in 2017. Gross G&A was \$10.6 million for the three months ended March 31, 2018 (three months ended March 31, 2017 - \$9.1 million). On a per boe basis net G&A for the period has declined 16 percent from the comparative period.

The Company's G&A expense is mainly denominated in local currencies of COP and Cdn dollar.

Share-Based Compensation Expense

For the three months ended March 31 (\$000s)		2018		2017
Equity settled share-based compensation	\$	3,513	\$	4,726
Cash settled share-based compensation		1,054		1,854
Share appreciation rights (recoveries)		(283)		(51)
Total net expense	\$	4,284	\$	6,529

Equity settled share-based compensation expense was \$3.5 million for the three months ended March 31, 2018 compared to \$4.7 million for the same period in 2017. 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. Overall the number of stock options outstanding has decreased from December 31, 2017 while the number of RSUs and PSUs outstanding has increased as stock options have become a smaller factor in the Company's compensation strategy.

Cash settled share-based compensation relates to the Company's cash settled incentive plans for its Colombian based employees and the Company's non-employee directors 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 March 31, 2018 there was an expense of \$1.1 million related to cash settled incentive plans compared to \$1.9 million expense for the same period in 2017. 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 14 of the consolidated interim financial statements for the three months ended March 31, 2018. As at March 31, 2018, the total cash settled incentive plans liability accrued is \$15.7 million (December 31, 2017 - \$16.6 million).



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

For the three months ended March 31,
(000s)

	2018	2017
DD&A	\$ 22,439	\$ 24,409
Per unit (\$/boe) ⁽¹⁾	6.14	8.32

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

First quarter 2018 DD&A was \$22.4 million (\$6.14/boe) compared to \$24.4 million (\$8.32/boe) for the same period in 2017. This decrease is due to the significant increase in proved and probable reserves and a change in the cash-generating unit ("CGU") production mix from the prior comparative period.

Foreign Exchange

For the three months ended March 31,

	2018	2017
Foreign exchange loss (000s)	\$ 4,579	\$ 1,584

Foreign Exchange Rates

USD\$/CAD\$⁽¹⁾

1.26

1.32

USD\$/Colombian peso⁽¹⁾

2,859

2,922

(1) Exchange rates shown are averages for the period.

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 driver of foreign exchange loss and gain recorded on the consolidated statements of comprehensive income is the Colombian Peso denominated tax withholdings receivable and income tax payable balances in Colombia. During the three months ended March 31, 2018, the total foreign exchange loss was \$4.6 million (three months ended March 31, 2017 – loss of \$1.6 million). The timing of payment settlements, accruals and their adjustments have impacts on foreign exchange gains/losses. 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.

The Company reviews its exposure to foreign currency variations on an ongoing basis and maintains cash deposits primarily in USD denominated deposits in Canada 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%	\$ 0.43	\$ (0.43)
Transportation expense	50%	\$ 0.21	\$ (0.21)
G&A expense	100%	\$ 0.22	\$ (0.22)

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 Q1 2018 per boe costs. This analysis ignores all other factors impacting cost structure including efficiencies, cost reduction strategies, etc.

Net Finance Expense

For the three months ended March 31,
(000s)

	2018	2017
Bank taxes and credit facility fees	\$ 420	\$ 909
Accretion on decommissioning and environmental liabilities	1,220	835
Interest and other income	(545)	(384)
Colombian net wealth tax	—	894
Net finance expense	\$ 1,095	\$ 2,254



For the three months ended March 31,
(000s)

	2018		2017	
Non-cash finance expense	\$	1,220	\$	835
Cash finance (income) expense		(125)		1,419
Net finance expense	\$	1,095	\$	2,254

Bank taxes and credit facility fees relate to bank taxes paid in Colombia and the standby fees related to the undrawn credit facility.

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 the 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 three months ended March 31, 2018:

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
January 1, 2018 to June 30, 2018	ICE Brent	5,000	\$ 47.00	\$ 50.00	—	\$ 0.27
April 1, 2018 to September 30, 2018	ICE Brent	10,000	\$ 50.00	\$ 55.00	—	\$ 0.40

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

For the three months ended March 31,	2018	2017
Premiums paid on commodity risk management contracts	180	1,189
Unrealized (gain) loss on commodity risk management contracts	216	(2,507)
Total	\$ 396	\$ (1,318)

The Company's net unrealized derivative loss on risk management contracts for the period ended March 31, 2018 was \$0.2 million (period ended March 31, 2017 - gain of \$2.5 million). The net unrealized loss is primarily attributable to the Brent forward benchmark price increasing since the time the derivative contracts were entered into. The realized loss on commodity risk management contracts including premiums paid for the period ended March 31, 2018 was \$0.2 million (period ended March 31, 2017 - loss of \$1.2 million). The premiums allowed Parex to enter into contracts that had higher purchase put prices than without the premiums.

b) Risk Management Contracts – Foreign Exchange

Subsequent to March 31, 2018, the Company entered into the following foreign currency risk management contract:

Period Hedged	Reference	Currency Option Type	Amount USD	Strike Price
April 25, 2018 to April 25, 2019	Colombian Peso	Costless Collar	\$20,000,000	2700-3025



Income Tax

The components of tax expense for the three months ended March 31, 2018 and 2017 were as follows:

For the three months ended March 31,	2018		2017	
Current tax expense	\$	27,280	\$	4,857
Deferred tax expense (recovery)		550		(1,277)
Total tax expense	\$	27,830	\$	3,580

Current tax in the first quarter of 2018 was \$27.3 million expense as compared to \$4.9 million current tax recovery in the comparative period. In the quarter current tax expense as a percentage of Colombian pre-tax cash flows was 21%. This increase is mainly a result of increased realized prices and the exhaustion of Colombian non-capital loss carry-forwards in 2017.

Deferred tax in the first quarter of 2018 was an expense of \$0.5 million (\$1.3 million recovery for the three months ended March 31, 2017).

For 2018 the Company continues to expect the effective tax rate on consolidated before tax cash flow to be approximately 20-25% at Brent crude prices of approximately \$70/bbl with potential variances based on timing and number of dry hole write-offs and the ending 2018 proved developed reserves which is an input for the calculation of tax depletion expense.

Capital Expenditures

For the three months ended March 31, (000s)	Colombia		Canada		Total	
	2018	2017	2018	2017	2018	2017
Acquisition of unproved properties	\$ (15)	\$ 125	—	—	\$ (15)	\$ 125
Geological and geophysical	1,873	(69)	—	—	1,873	(69)
Drilling and completion	47,994	32,278	—	—	47,994	32,278
Well equipment and facilities	8,356	3,205	—	—	8,356	3,205
Other	—	—	2	24	2	24
	\$ 58,208	\$ 35,539	\$ 2	\$ 24	\$ 58,210	\$ 35,563

Capital Expenditures Summary

During the three months ended March 31, 2018 the Company incurred \$58.2 million of capital expenditures compared to \$35.6 million in the same period of 2017. During Q1, 2018 the Company drilled 12 gross (8.85 net) wells compared to 9 gross (5.25 net) in Q1, 2017. Drilling and completion costs during the first quarter totaled \$48.0 million, which relates to drilling and completion costs mainly on Block LLA-34 and Cabrestero Block.



Summary of Quarterly Results

Three months ended (\$000s)	March 31, 2018	Dec. 31, 2017	Sep. 30, 2017	June 30, 2017
Average daily oil and natural gas production (boe/d)	40,586	39,007	36,195	34,291
Average realized sales price – oil and natural gas (\$/boe) ⁽¹⁾	55.98	50.43	41.16	40.26
Financial (000s except per share amounts)				
Oil and natural gas sales ⁽¹⁾	\$ 202,450	180,738	136,956	124,995
Funds flow provided by operations	\$ 100,901	\$ 93,861	\$ 65,998	\$ 51,763
Per share – basic	0.65	0.61	0.43	0.34
Per share – adjusted diluted ⁽²⁾	0.64	0.59	0.42	0.33
Net income	\$ 71,512	\$ 55,921	\$ 55,527	\$ 3,524
Per share – basic	0.46	0.36	0.36	0.02
Per share – diluted	0.45	0.36	0.35	0.02
Capital Expenditures, excluding corporate acquisitions	\$ 58,210	\$ 66,341	\$ 51,434	\$ 59,008
Total assets (end of period)	\$ 1,229,897	\$ 1,121,908	\$ 1,057,859	\$ 1,015,540
Working capital surplus (end of period) ⁽³⁾	\$ 205,771	\$ 163,401	\$ 140,292	\$ 128,347

(1) In Q1 2018 the Company changed its accounting policy regarding revenue and transportation costs on certain oil sale contracts. The change has no impact on operating netback, cash flow or net income. For further information refer to the 'Impact of Accounting Policy Change' section on page 5.

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

(3) Working capital does not include the undrawn amount available on the credit facility.

Three months ended (\$000s)	March 31, 2017	Dec. 31, 2016	Sep. 30, 2016	June 30, 2016
Average daily oil and natural gas production (boe/d)	32,591	31,049	29,754	29,136
Average realized sales price – oil and natural gas (\$/boe) ⁽¹⁾	42.21	36.96	35.73	35.95
Financial (000s except per share amounts)				
Oil and natural gas sales ⁽¹⁾	130,079	112,201	113,367	94,601
Funds flow provided by operations	\$ 67,906	\$ 51,791	\$ 45,091	\$ 31,792
Per share – basic	0.44	0.34	0.30	0.21
Per share – adjusted diluted ⁽²⁾	0.43	0.33	0.29	0.20
Net (loss) income	\$ 40,106	\$ (45,439)	\$ 6,811	\$ (185)
Per share – basic	0.26	(0.30)	0.04	0.00
Per share – diluted	0.26	(0.30)	0.04	0.00
Capital Expenditures, excluding corporate acquisitions	\$ 35,563	\$ 66,890	\$ 26,313	\$ 13,922
Total assets (end of period)	\$ 984,855	\$ 918,671	\$ 947,354	\$ 921,665
Working capital surplus (end of period) ⁽³⁾	\$ 131,056	\$ 93,290	\$ 117,747	\$ 97,532

(1) In Q1 2018 the Company changed its accounting policy regarding revenue and transportation costs on certain oil sale contracts. The change has no impact on operating netback, cash flow or net income. For further information refer to the 'Impact of Accounting Policy Change' section on page 5.

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

(3) Working capital does not include the undrawn amount available on the credit facility.

Factors that Caused Variations Quarter Over Quarter

During the first quarter of 2018, production of 40,586 boe/d was in excess of oil production for the previous quarter ended December 31, 2017. Revenue and funds flow from operations was higher than the previous quarter mainly due to an increase in volumes sold and higher realized prices. Working capital has increased to \$205.8 million from \$163.4 million at December 31, 2017 mainly due to funds flow provided by operating activities of \$100.9 million being in excess of capital expenditures of \$58.2 million.



During the fourth quarter of 2017, production of 39,007 boe/d was in excess of production compared to the previous quarter ended September 30, 2017. Revenue was higher than the previous quarter due to a increased sales volumes and a significant 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. Capital expenditures for the fourth quarter of 2017 were \$66.3 million compared to \$51.4 million in the prior quarter mainly related to drilling on Block LLA-34, Cabrestero Block, and Capachos Block.

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 a 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, Cabrestero 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 \$35.6 million in the prior quarter mainly related to drilling on Block LLA-34, Cabrestero 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.

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 March 31, 2018 the Company had a working capital surplus of \$205.8 million, excluding funds available under the credit facility, as compared to working capital surplus at December 31, 2017 of \$163.4 million and a working capital surplus of \$131.1 million in the comparative period. Bank debt was \$nil at March 31, 2018, December 31, 2017 and March 31, 2017. The credit facility has a current borrowing base of \$100.0 million and is subject to a borrowing base redetermination in October 2018. At March 31, 2018 Parex held \$294.5 million of cash, compared to \$235.0 million at December 31, 2017 and \$184.6 million at March 31, 2017. 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 funds flow from operations in excess of capital expenditures for the three months ended March 31, 2018.

Parex' syndicated senior secured credit facility ("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 March 31, 2018, the Company is in compliance with all covenants. The next annual review is scheduled to occur at the end of October 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 2018 to utilize the credit facility, the next re-determination is not expected to impact the Company's current or future operations or reduce the 2018 outlook.

In the fourth quarter of 2017 the Company put in place an automatic share purchase plan with a broker in order to facilitate repurchases of up to 3.0 million of its common shares. Under the Company's automatic share purchase plan, the Company's broker may repurchase shares under the normal course issuer bid during the Company's self-imposed blackout periods. The Company expects to renew the automatic share purchase plan in 2018 and therefore to ultimately buy back approximately 4.0 million of its common shares in 2018. The repurchase plan is seen by management as a way to support shareholders, reduce dilution of common shares when stock based share exercises occur, and provide additional liquidity to holders of common shares.

Refer to note 21 - Commitments of the interim financial statements for the period ended March 31, 2018 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 March 31, 2018 the Company had 155,646,553 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 9 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 May 8, 2018 Parex has the following securities outstanding:

	Number	%
Common shares	155,893,857	95 %
Stock options	4,648,132	3 %
Restricted and performance share units	3,098,853	2 %
	163,640,842	100%

As of the date of this MD&A, total stock options, RSUs and PSUs outstanding represent approximately 5 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. 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 March 31, 2018 were \$126.0 million (December 31, 2017 - \$142.6 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, 2017 - \$250.0 million) performance guarantee facility to support approximately \$99.6 million (December 31, 2017 - \$116.1 million) of the letters of credit issued on behalf of Parex at March 31, 2018. The letters of credit issued to the ANH are reduced from time to time to reflect the work performed on the various blocks.

The following table summarizes the Company's estimated commitments as at March 31, 2018:

(000s)	Total	<1 year	1 – 3 years	3 – 5 years	>5 years
Exploration	\$ 154,007	135,902	18,105	—	—
Office and accommodations ⁽¹⁾	7,001	1,714	2,231	1,687	1,369
Decommissioning and Environmental Obligations	96,236	9,632	—	—	86,604
Total	\$ 257,244	147,248	20,336	1,687	87,973

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



Decommissioning and Environmental Liabilities

	Decommissioning	Environmental	Total
Balance, December 31, 2016	\$ 38,720	\$ 12,426	\$ 51,146
Additions	5,313	2,223	7,536
Settlements of obligations during the year	(954)	(437)	(1,391)
Accretion expense	2,549	1,416	3,965
Additions related to change in estimate - inflation and discount rates	(9,773)	(1,809)	(11,582)
Additions related to change in estimate - costs	391	2,499	2,890
Foreign exchange loss (gain)	528	(412)	116
Balance, December 31, 2017	\$ 36,774	\$ 15,906	\$ 52,680
Additions	1,419	838	2,257
Settlements of obligations during the period	(835)	(40)	(875)
Accretion expense	627	593	1,220
Foreign exchange loss	2,719	1,067	3,786
Balance, March 31, 2018	\$ 40,704	\$ 18,364	\$ 59,068
Current obligation	(3,470)	(6,162)	(9,632)
Long-term obligation	\$ 37,234	\$ 12,202	\$ 49,436

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 March 31, 2018, 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 \$72.7 million as at March 31, 2018 (December 31, 2017 – \$66.4 million) with the majority of these costs anticipated to occur in 2021 or later. 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, 2017 – 7.5 percent risk-free discount rate and a 4.0 percent inflation rate). The risk-free discount rate and the inflation rate used are based on forecast Colombia rates.

Included in the decommissioning liability is \$3.5 million (December 31, 2017 – \$4.2 million) that is classified as a current obligation. Parex expects to settle the short term obligation in 2018 with the majority of the work performed in the second half of 2018.

The total undiscounted amount of cash flows required to settle the Company's environmental liability is approximately \$23.5 million as at March 31, 2018 (December 31, 2017 – \$19.0 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, 2017 – 7.5 percent risk-free discount rate and a 4.0 percent inflation rate). The risk-free discount rate and the inflation rate used are based on forecast Colombia rates.

Included in the environmental liability is \$6.2 million (December 31, 2017 – \$5.6 million) that is classified as a current obligation. Similar to the settlement of the company's short term decommissioning liability the company expects the majority of this work to be performed in the second half of 2018.

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:

- Parex' expectation that it will invest \$260 - \$290 million in capital projects in 2018;
- expectations that activity levels will increase significantly in the second and third quarters of 2018;
- 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;
- the Company's capital program budget for 2018, including the expected allocation of such expenditures and the Company's plans to fund its 2018 capital program from funds flow from operations;
- expected timing of the draw down of crude oil inventories in transit;
- 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 and production costs;
- 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 estimated effective current tax rate 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 2018 outlook;
- benefits derived from the normal course issuer bid and the automatic share purchase plan and the expectation that the bid and plan will be renewed in 2018; and
- estimated amounts, timing and the anticipated sources of funding for the Company's exploration, office and accommodations, environmental, decommissioning and restoration obligations.

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" 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, operating netback per boe, free funds flow, basic and diluted funds flow per share and adjusted EBITDA 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.

Basic and 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 basic and diluted funds flow per share:



For the three months ended March 31,

(\$000s)	2018	2017
Funds flow provided by operations	\$ 100,901	\$ 67,906
Weighted average number of shares for the purposes of basic funds flow (\$000s)	155,037	153,284
Dilutive effect of share options on potential common shares	3,053	3,418
Weighted average number of shares for the purposes of diluted funds flow	158,090	156,702

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 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:

For the three months ended March 31,

(\$000s)	2018	2017
Oil and natural gas revenue excluding risk management contracts	\$ 202,450	130,079

Denominator (BOEs)

Company produced oil and natural gas sales in period	3,591,090	3,022,380
Purchased oil volumes sold	25,650	59,130
Total oil and natural gas sales volumes	3,616,740	3,081,510

Sales price per boe	\$ 55.98	\$ 42.21
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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:

For the three months ended March 31,

(\$000s)	2018	2017
Royalty expense	\$ 26,179	\$ 13,252

Denominator (BOEs)

Company produced oil and natural gas sales in period	3,591,090	3,022,380
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Royalty expense per boe	\$ 7.29	\$ 4.38
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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:

For the three months ended March 31,

(\$000s)	2018	2017
Production Expense	\$ 19,202	\$ 15,389

Denominator (BOEs)

Company produced oil and natural gas sales in period	3,591,090	3,022,380
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Production expense per boe	\$ 5.35	\$ 5.09
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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:

For the three months ended March 31,
(\$000s)

	2018	2017
Transportation Expense	\$ 15,343	14,180
Denominator (BOEs)		
Company produced oil and natural gas sales in period	3,591,090	3,022,380
Purchased oil volumes sold	25,650	59,130
Total oil and natural gas sales volumes	3,616,740	3,081,510
Transportation expense per boe	\$ 4.24	\$ 4.60

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

For the three months ended March 31,
(\$000s)

	2018	2017
Funds flow provided by operations	\$ 100,901	\$ 67,906
Capital expenditures, excluding corporate acquisitions	58,210	35,563
Free cash flow	\$ 42,691	\$ 32,343

Impact of Accounting Policy Change

On January 1st, 2018 Parex adopted a new accounting policy that changed to the way the Company records revenue and transportation costs on certain oil sale contracts. The change resulted in a decrease in revenue and a corresponding decrease in transportation expense. There is no impact on cash flows, net income or overall operating netback. Refer to the reconciliation below for the impact of the adoption on prior period revenue and transportation expense, including per boe amounts:

Three months ended (\$000s)	Dec. 31, 2017	Sep. 30, 2017	June 30, 2017	March 31, 2017
Average realized sales price – oil and natural gas (\$/boe) prior period	56.90	48.07	46.84	48.72
Adjustment on certain oil sales contracts	(6.47)	(6.91)	(6.58)	(6.51)
Average realized sales price – oil and natural gas (\$/boe) adjusted	50.43	41.16	40.26	42.21
Oil and natural gas sales prior period	203,930	159,929	145,406	150,142
Adjustment on certain oil sales contracts	(23,192)	(22,973)	(20,411)	(20,063)
Oil and natural gas sales adjusted	180,738	136,956	124,995	130,079
Transportation expense - (\$/boe) prior period	10.52	10.72	10.91	11.11
Adjustment on certain oil sales contracts	(6.47)	(6.91)	(6.58)	(6.51)
Transportation expense - (\$/boe) adjusted	4.05	3.81	4.33	4.60
Transportation expense prior period	37,694	35,678	33,860	34,243
Adjustment on certain oil sales contracts	(23,192)	(22,973)	(20,411)	(20,063)
Transportation expense adjusted	14,502	12,705	13,449	14,180

Business Environment and Risks

There have been no significant changes during the three ended March 31, 2018 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 three months ended March 31, 2018.

Financial Instruments and Other Instruments

The Company's non-derivative financial instruments recognized in 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.

Accounting Policies and Estimates

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, 2017, except for the following adoption of new accounting standards effective January 1, 2018:

a) Adoption of IFRS 15, Revenues From Contracts With Customers

The Company adopted IFRS 15, "Revenue from Contracts with Customers" on January 1, 2018. The Company used the retrospective adoption approach to adopt the new standard. In conjunction with the adoption of IFRS 15, the Company reviewed its revenue streams and major contracts with customers. As a result of this review, the Company changed the way it records revenue and transportation costs on certain oil sale contracts. The change resulted in a \$20.1 million reduction to revenue in the three months ended March 31, 2017 with a corresponding reduction of \$20.1 million to transportation expense. The effect of the reclassification on the prior period is presented below:

For the three months ended

(000s)		March 31, 2017
Decrease in sales of crude oil	\$	(20,063)
Decrease in transportation expense		(20,063)
Impact on net income	\$	—

There was no material impact on the Company's net income and financial position resulting from this change and there was no effect to the opening deficit from the application of IFRS 15 to revenue contracts in progress at January 1, 2018. The additional disclosures required by IFRS 15 are detailed in Note 9 - Revenue.

The following accounting policy is applicable from January 1, 2018:

Parex principally generates revenue from the sale of commodities, which include crude oil and natural gas. Revenue associated with the sale of commodities is recognized when control is transferred from Parex to its customers. The Company's commodity sale contracts represent a series of distinct transactions. The Company considers its performance obligations to be satisfied and control to be transferred when all the following conditions are satisfied:

- Parex has transferred title and physical possession of the commodity to the buyer;
- Parex has transferred the significant risks and rewards of ownership of the commodity to the buyer; and
- Parex has the present right to payment.

Revenue is measured based on the consideration specified in a contract with a customer and excludes amounts collected on behalf of third parties. The Company sells its production of crude oil and natural gas pursuant to variable price contracts. The transaction price for variable price contracts is based on the commodity price, adjusted for quality, location and other factors. The amount of revenue recognized is based on the agreed transaction price with any variability in transaction price recognized in the same period. The Company does not have any contracts where the period between the transfer of the promised goods or services to the customer and payment by the customer exceeds one year. As a result, Parex does not adjust its revenue transactions for the time value of money.

Parex enters into contracts with customers that can have performance obligations that are unsatisfied (or partially unsatisfied) at the reporting date. The Company applies a practical expedient of IFRS 15 and does not disclose information about remaining performance obligations that have original expected durations of one year or less, or for performance obligations where the Company has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of the Company's performance completed to date. The company also applies



a practical expedient of IFRS 15 that allows any incremental costs of obtaining contracts with customers to be recognized as an expense when incurred rather than being capitalized.

Contract modifications with the Company's customers could change the scope of the contract, the price of the contract, or both. A contract modification exists when the parties to the contract approve the modification either in writing, orally, or based on the parties' customary business practices. Contract modifications are accounted for either as a separate contract when there is an additional product at a stand alone selling price, or as part of the existing contract, through either a cumulative catch-up adjustment or prospectively over the remaining term of the contract, depending on the nature of the modification and whether the remaining products are distinct.

The Company's revenue transactions do not contain significant financing components.

b) Adoption of IFRS 9, Financial Instruments

Effective January 1, 2018, the Company adopted IFRS 9, Financial Instruments (IFRS 9), which replaced IAS 39, Financial Instruments: Recognition and Measurement (IAS 39). The Company applied the new standard retrospectively and the adoption of IFRS 9 did not have a material impact on the Company's consolidated financial statements and did not result in any adjustments to the amounts recognized in the Company's consolidated financial statements for the year ended December 31, 2017. The nature and effects of the key changes to the Company's accounting policies resulting from the adoption of IFRS 9 are summarized below.

Classification of Financial Assets and Financial Liabilities

IFRS 9 contains three principal classification categories for financial assets: measured at amortized cost, fair value through other comprehensive income (FVOCI) and fair value through profit or loss (FVTPL). The previous IAS 39 categories of held to maturity, loans and receivables and available for sale are eliminated. IFRS 9 bases the classification of financial assets on the contractual cash flow characteristics and the company's business model for managing the financial asset. Additionally, embedded derivatives are not separated if the host contract is a financial asset within the scope of IFRS 9. Instead, the entire hybrid contract is assessed for classification and measurement.

IFRS 9 largely retains the existing requirements in IAS 39 for the classification of financial liabilities. The differences between the two standards did not impact the Company at the time of transition.

The following table shows the original measurement categories under IAS 39 and the new measurement categories under IFRS 9 as at January 1, 2018 for each class of the Company's financial assets and financial liabilities:

Financial Instrument	Measurement Category ⁽¹⁾	
	IAS 39	IFRS 9
Cash and cash equivalents	Loans and receivables (measured at amortized cost)	Amortized cost
Accounts receivable	Loans and receivables (measured at amortized cost)	Amortized cost
Accounts payable and accrued liabilities	Other financial liabilities (measured at amortized cost)	Amortized cost
Derivative financial instruments	FVTPL	FVTPL

(1) There were no adjustments to the carrying amounts of financial instruments as a result of the change in classification from IAS 39 to IFRS 9.

Impairment of financial assets

IFRS 9 replaces the "incurred loss" model in IAS 39 with an "expected credit loss" ("ECL") model. The new impairment model applies to financial assets measured at amortized cost. Under IFRS 9, credit losses are recognized earlier than under IAS 39.

The ECL model applies to the Company's receivables. As at March 31, 2018, 99 percent of the Company's receivables were outstanding for less than 60 days. The average expected credit loss on the Company's trade accounts receivable was 0.2 percent at March 31, 2018.

On January 1, 2018, the Company identified the business model used to manage its financial assets and classified its financial instruments into the appropriate IFRS 9 categories as shown in the table above and applied the ECL model to financial assets classified as measured at amortized cost. The classification and measurement of financial instruments under IFRS 9 did not have a material impact on the Company's opening retained earnings as at January 1, 2018. In addition, the application of the ECL model to financial assets classified as measured at amortized cost did not result in a material adjustment on transition.

The following accounting policy is applicable from January 1, 2018:

Financial instruments are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets and liabilities are not offset unless the Company has the current legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously.



The Company characterizes its fair value measurements into a three-level hierarchy depending on the degree to which the inputs are observable, as follows:

- Level 1 inputs are quoted prices in active markets for identical assets and liabilities;
- Level 2 inputs are inputs, other than quoted prices included within Level 1, that are observable for the asset or liability either directly or indirectly; and
- Level 3 inputs are unobservable inputs for the asset or liability.

Classification and Measurement of Financial Assets

The initial classification of a financial asset depends upon the Company's business model for managing its financial assets and the contractual terms of the cash flows. There are three measurement categories into which the Company classified its financial assets:

- **Amortized Cost:** Includes assets that are held within a business model whose objective is to hold assets to collect contractual cash flows and its contractual terms give rise on specified dates to cash flows that represent solely payments of principal and interest;
- **FVOCI:** Includes assets that are held within a business model whose objective is achieved by both collecting contractual cash flows and selling the financial assets, where its contractual terms give rise on specified dates to cash flows that represent solely payments of principal and interest; or
- **FVTPL:** Includes assets that do not meet the criteria for amortized cost or FVOCI and are measured at fair value through profit or loss. This includes all derivative financial instruments.

On initial recognition, the Company may irrevocably designate a financial asset that meets the amortized cost or FVOCI criteria as measured at FVTPL if doing so eliminates or significantly reduces an accounting mismatch. On initial recognition of an equity investment that is not held-for-trading, the Company may irrevocably elect to present subsequent changes in the investment's fair value in OCI. There is no subsequent reclassification of fair value changes to earnings following the derecognition of the investment. However, dividends that reflect a return on investment continue to be recognized in net earnings. This election is made on an investment-by-investment basis.

At initial recognition, the Company measures a financial asset at its fair value and, in the case of a financial asset not at FVTPL, including transaction costs that are directly attributable to the acquisition of the financial asset. Transaction costs of financial assets carried at FVTPL are recorded as an expense in net earnings.

Financial assets are reclassified subsequent to their initial recognition only if the business model for managing those financial assets changes. The affected financial assets will be reclassified on the first day of the first reporting period following the change in the business model. A financial asset is derecognized when the rights to receive cash flows from the asset have expired or have been transferred and the Company has transferred substantially all the risks and rewards of ownership.

Impairment of Financial Assets

The Company recognizes loss allowances for ECLs on its financial assets measured at amortized cost. Due to the nature of its financial assets, the Company measures loss allowances at an amount equal to expected lifetime ECLs. Lifetime ECLs are the anticipated ECLs that result from all possible default events over the expected life of a financial asset. ECLs are a probability-weighted estimate of credit losses. Credit losses are measured as the present value of all cash shortfalls (i.e. the difference between the cash flows due to the entity in accordance with the contract and the cash flows that the Company expects to receive). ECLs are discounted at the effective interest rate of the related financial asset. The Company does not have any financial assets that contain a financing component

Classification and Measurement of Financial Liabilities

A financial liability is initially classified as measured at amortized cost or FVTPL. A financial liability is classified as measured at FVTPL if it is held-for-trading, a derivative, or designated as FVTPL on initial recognition. The classification of a financial liability is irrevocable.

Financial liabilities at FVTPL are measured at fair value with changes in fair value, along with any interest expense, recognized in net earnings. Other financial liabilities are initially measured at fair value less directly attributable transaction costs and are subsequently measured at amortized cost using the effective interest method. Interest expense and foreign exchange gains and losses are recognized in net earnings. Any gain or loss on derecognition is also recognized in net earnings.

A financial liability is derecognized when the obligation is discharged, cancelled or expired. When an existing financial liability is replaced by another from the same counterparty with substantially different terms, or the terms of an existing liability are substantially modified, it is treated as a derecognition of the original liability and the recognition of a new liability. When the terms of an existing financial liability are altered, but the changes are considered non-substantial, it is accounted for as a modification to the existing financial liability. Where a liability is substantially modified it is considered to be extinguished and a gain or loss is recognized in net earnings based on the difference between the



carrying amount of the liability derecognized and the fair value of the revised liability. Where a liability is modified in a non-substantial way, the amortized cost of the liability is remeasured based on the new cash flows and a gain or loss is recorded in net earnings.

Derivative Financial Instruments

Derivative financial instruments are used to manage economic exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Policies and procedures are in place with respect to required documentation and approvals for the use of derivative financial instruments. Where specific financial instruments are executed, the Company assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in the particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

Risk management assets and liabilities are derivative financial instruments classified as measured at FVTPL unless designated for hedge accounting. Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using mark-to-market accounting whereby instruments are recorded in the consolidated balance sheets as either an asset or liability with changes in fair value recognized in net earnings as a gain or loss on risk management. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third-party market indications and forecasts.

New Accounting Standards Not Yet Adopted

On January 13, 2016, the IASB issued IFRS 16, "Leases". The standard is required to be adopted either retrospectively or by recognizing the cumulative effect of initially applying IFRS 16 as an adjustment to opening equity at the date of initial application. IFRS 16 is effective for fiscal years beginning on or after January 1, 2019. Under the new standard, companies will recognize new assets and liabilities, bringing off-balance-sheet leasing arrangements onto the balance sheet. The Company intends to adopt IFRS 16 in its financial statements for the annual period beginning on January 1, 2019. Although the transition approach on adoption has not yet been determined, it is anticipated that the adoption of IFRS 16 will have a material impact on the Company's financial statements.

DIRECTORS

Wayne K. Foo
Chairman of the Board

Curtis D. Bartlett

Lisa Colnett

Robert J. Engbloom

Bob MacDougall

Glenn McNamara

Ron D. Miller

Carmen Sylvain

David R. Taylor

Paul D. Wright

OFFICERS & SENIOR EXECUTIVES

David R. Taylor
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
Chief Operating Officer

Michael Kruchten
Vice President, Capital Markets & Corporate Planning

CORPORATE HEADQUARTERS

Parex Resources Inc.
2700, Eighth Avenue Place, West Tower
585 8 Avenue S.W.,
Calgary, Alberta, Canada T2P 1G1

Tel: 403-265-4800
Fax: 403-265-8216
E-mail: info@parexresources.com

OPERATING OFFICES

Parex Resources Colombia Ltd. Sucursal
Calle 113 No. 7-21, Of. 611,
Edificio Teleport, Torre A,
Bogotá, Colombia

Tel: 571-629-1716
Fax: 571-629-1786

AUDITORS

PricewaterhouseCoopers LLP
Calgary, Alberta

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP
Calgary, Alberta

TRANSFER AGENT AND REGISTRAR

Computershare Trust Company of Canada
Calgary, Alberta

RESERVES EVALUATORS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

INVESTOR RELATIONS

Michael Kruchten
Vice President, Capital Markets & Corporate Planning

Tel: 403-517-1733
Fax: 403-265-8216

E-mail:
Investor.Relations@parexresources.com

Website: www.parexresources.com

ABBREVIATIONS**Oil and Natural Gas Liquids**

bbl	barrel
bbls	barrels
mmbbls	one thousand barrels
mmbbls	one million barrels
NGLs	natural gas liquids
bbl/d	barrel of oil per day
bbls/d	barrels of oil per day
mmbbls/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
mamboe	one million barrels of oil equivalent
bfpd	barrels of fluid per day
boe/d	barrels of oil equivalent per day
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day

Other

WTI	West Texas Intermediate
Brent	Brent Ice
Vasconia	Vasconia Crude

"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.

