CONSOLIDATED INTERIM FINANCIAL STATEMENTS

Consolidated Balance Sheets (unaudited)

As at (thousands of United States dollars)	NOTE		**June 30, 2018**		December 31, 2017
ASSETS					
Current assets					
Cash and cash equivalents		**$**	**323,134**	$	235,042
Accounts receivable	**5**		**124,333**		79,152
Prepaids and other current assets			**7,118**		1,828
Crude oil inventory	**6**		**4,701**		3,038
			459,286		319,060
Deferred tax asset	**15**		**229,154**		20,815
Goodwill			**73,452**		73,452
Exploration and evaluation	**7**		**168,713**		107,144
Property, plant and equipment	**8**		**655,644**		601,437
		$	**1,586,249**	$	1,121,908
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities					
Accounts payable and accrued liabilities		**$**	**186,653**	$	103,509
Derivative financial instruments	**19**		**1,760**		116
Current income tax payable	**15**		**194,678**		42,266
Current portion of decommissioning and environmental liabilities	**12**		**10,145**		9,768
			393,236		155,659
Other long-term liabilities	**11**		**8,510**		4,718
Decommissioning and environmental liabilities	**12**		**48,643**		42,912
Deferred tax liability	**15**		**—**		30,345
			450,389		233,634
Shareholders' equity					
Share capital	**13**		**850,854**		836,166
Contributed surplus			**49,069**		52,431
Retained Earnings (deficit)			**235,937**		(323)
			1,135,860		888,274
		$	**1,586,249**	$	1,121,908

Commitments (note 21)
Subsequent Event (note 22)
See accompanying Notes to the Consolidated Interim Financial Statements
Approved by the Board:

Paul Wright
Director

Ron Miller
Director

Consolidated Statements of Comprehensive Income (unaudited)

(thousands of United States dollars, except per share amounts)	NOTE	For the three months ended June 30, 2018	2017	For the six months ended June 30, 2018	2017
Oil and natural gas sales	9	**$ 241,765**	$ 124,995	**$ 444,215**	$ 255,074
Royalties		**(31,177)**	(12,421)	**(57,356)**	(25,673)
Revenue		**210,588**	112,574	**386,859**	229,401
Commodity risk management contracts gain (loss)	19	**(390)**	1,091	**(786)**	2,409
		210,198	113,665	**386,073**	231,810
Expenses					
Production		**22,193**	16,363	**41,395**	31,752
Transportation		**12,200**	13,449	**27,543**	27,629
Purchased oil		**3,167**	912	**4,603**	3,286
General and administrative		**7,930**	8,399	**16,085**	16,139
Legal settlement		**—**	15,000	**—**	15,000
Equity settled share-based compensation	13	**3,496**	5,045	**7,009**	9,771
Cash settled share-based compensation	14	**10,392**	(1,002)	**11,163**	801
Depletion, depreciation and amortization	8	**24,218**	25,906	**46,657**	50,315
Foreign exchange (gain) loss		**(868)**	(2,527)	**3,711**	(943)
		82,728	81,545	**158,166**	153,750
Finance (income)	10	**(953)**	(492)	**(1,498)**	(876)
Finance expense	10	**5,934**	1,966	**7,574**	4,604
Net finance expense		**4,981**	1,474	**6,076**	3,728
Net income before income taxes		**122,489**	30,646	**221,831**	74,332
Income tax expense (recovery)					
Current tax expense	15	**173,122**	7,505	**200,402**	12,362
Deferred tax (recovery) expense	15	**(239,234)**	19,617	**(238,684)**	18,340
		(66,112)	27,122	**(38,282)**	30,702
Net income and comprehensive income for the period		**$ 188,601**	$ 3,524	**$ 260,113**	$ 43,630
Basic net income per common share	16	**$ 1.21**	$ 0.02	**$ 1.67**	$ 0.28
Diluted net income per common share	16	**$ 1.18**	$ 0.02	**$ 1.63**	$ 0.28

See accompanying Notes to the Consolidated Interim Financial Statements

Consolidated Statements of Changes in Equity (unaudited)

For the six months ended June 30, (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		**24,255**		9,458
Repurchase of shares		**(9,567)**		—
Balance, end of period		**850,854**		831,685
Contributed surplus				
Balance, beginning of period		**52,431**		42,208
Share-based compensation		**7,009**		9,771
Options exercised		**(10,371)**		(3,788)
Contributed surplus attributed to DSUs transferred to cash settled liability		**—**		(1,396)
Balance, end of period		**49,069**		46,795
Retained Earnings (deficit)				
Balance, beginning of period		**(323)**		(150,643)
Net income for the period		**260,113**		43,630
Repurchase of shares		**(23,853)**		—
Balance, end of period		**235,937**		(107,013)
	$	**1,135,860**	$	771,467

See accompanying Notes to the Consolidated Interim Financial Statements

Consolidated Statements of Cash Flows (unaudited)

(thousands of United States dollars)	NOTE	For the three months ended June 30, 2018	2017	For the six months ended June 30, 2018	2017
Operating activities					
Net income		**$ 188,601**	$ 3,524	**$ 260,113**	$ 43,630
Add (deduct) non-cash items					
Depletion, depreciation and amortization	**8**	**24,218**	25,906	**46,657**	50,315
Non-cash finance expense	**10**	**2,369**	1,174	**3,589**	2,009
Equity settled share-based compensation	**13**	**3,496**	5,045	**7,009**	9,771
Cash settled share-based compensation (recovery)	**14**	**10,392**	(1,002)	**11,163**	801
Deferred tax (recovery) expense	**15**	**(239,234)**	19,617	**(238,684)**	18,340
Unrealized foreign exchange loss (gain)		**(786)**	830	**2,730**	1,426
Unrealized (gain) loss on commodity risk management contracts	**19**	**26**	(730)	**242**	(3,237)
Loss on settlement of decommissioning liabilities		**2,981**	—	**2,981**	—
Abandonment costs paid		**(3,052)**	(81)	**(3,927)**	(281)
Cash settled incentive plans paid		**(4,776)**	(2,520)	**(6,737)**	(3,105)
Funds flow (used in) provided by operations		**(15,765)**	51,763	**85,136**	119,669
Net change in non-cash working capital	**17**	**102,368**	28,041	**114,160**	13,506
Cash provided by operating activities		**86,603**	79,804	**199,296**	133,175
Investing activities					
Property, plant and equipment expenditures	**8**	**(58,101)**	(53,314)	**(97,381)**	(77,995)
Exploration and evaluation expenditures	**7**	**(42,466)**	(5,694)	**(61,396)**	(16,576)
Net change in non-cash working capital	**17**	**60,046**	(4,525)	**67,544**	10,028
Cash (used in) investing activities		**(40,521)**	(63,533)	**(91,233)**	(84,543)
Financing activities					
Issuance of common shares under share-based compensation plans	**13**	**5,586**	2,760	**13,884**	5,670
Common shares repurchased	**13**	**(22,269)**	—	**(33,420)**	—
Cash (used in) provided by financing activities		**(16,683)**	2,760	**(19,536)**	5,670
Increase in cash for the period		**29,399**	19,031	**88,527**	54,302
Impact of foreign exchange on foreign currency-denominated cash balances		**(762)**	(782)	**(435)**	(652)
Cash, beginning of period		**294,497**	184,647	**235,042**	149,246
Cash, end of period		**$ 323,134**	$ 202,896	**$ 323,134**	$ 202,896

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

1. Corporate Information

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

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

The condensed interim consolidated financial statements were approved and authorized for issuance by the Board of Directors on August 8, 2018.

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

a) Statement of compliance

The condensed interim consolidated financial information for the three and six months ended June 30, 2018 has been prepared in accordance with IAS 34, 'Interim financial reporting'. The condensed interim consolidated financial information should be read in conjunction with the annual financial statements for the year ended December 31, 2017, which have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB").

The policies applied in these condensed interim consolidated financial statements are based on IFRS issued and outstanding as of August 8, 2018, the date of approval by the Board of Directors.

b) Basis of measurement

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

c) Use of management estimates, judgments and measurement uncertainty

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

In preparing these condensed interim consolidated financial statements, the significant judgements made by management in applying the group's accounting policies and the key sources of estimation uncertainty were the same as those that applied to the consolidated financial statements for the year ended December 31, 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 $20.4 million reduction to revenue in the three months ended June 30, 2017 with a corresponding reduction of $20.4 million to transportation expense. The effect of the reclassification on the prior period is presented below:

(000s)	For the three months ended June 30, 2017	For the six months ended June 30, 2017
Decrease in sales of crude oil	$ (20,411)	$ (40,474)
Decrease in transportation expense	(20,411)	(40,474)
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:

	Measurement Category (1)	
Financial Instrument	**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 June 30, 2018, all 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 0.3 percent at June 30, 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

		June 30, 2018		December 31, 2017
Trade receivables	**$**	**52,811**	$	28,366
Colombia income taxes receivable		**56,557**		36,843
Value added taxes (VAT)		**14,965**		13,943
	$	**124,333**	$	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 $15.0 million as at June 30, 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

		June 30, 2018		December 31, 2017
Crude oil inventory	**$**	**4,701**	$	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

		Colombia Total
Cost		
Balance at 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		61,396
Changes in decommissioning liability		173
Balance, June 30, 2018	**$**	**168,713**

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 $61.4 million for the six months ended June 30, 2018 represent the Company's share of costs incurred on E&E assets during the period. For the six months ended June 30, 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 capital expenditures on block VMM-11 in the Middle Magdalena basin deemed to be unrecoverable.

At June 30, 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		79		97,302		97,381
Changes in decommissioning and environmental liability		—		4,066		4,066
Balance, June 30, 2018	**$**	**3,859**	**$**	**1,889,190**	**$**	**1,893,049**
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		73		46,584		46,657
DD&A included in crude oil inventory costing		—		583		583
Balance, June 30, 2018	**$**	**3,606**	**$**	**1,233,799**	**$**	**1,237,405**
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 June 30, 2018	**$**	**253**	**$**	**655,391**	**$**	**655,644**

In the six months ended June 30, 2018 property, plant and equipment ("PPE") additions of $97.4 million mainly relate to drilling costs in Colombia mainly at Block LLA-34, Aguas Blancas and Cabrestero blocks. For the six months ended June 30, 2018, no E&E assets were transferred to PP&E (six months ended June 30, 2017 - $26.4 million E&E assets were transferred to PP&E).

For the six months ended June 30, 2018 future development costs of $348.5 million (six months ended June 30, 2017 - $346.5 million) were included in the depletion calculation for development and production assets. For the six months ended June 30, 2018 $4.8 million of general and administrative costs (six months ended June 30, 2017 - $3.9 million) have been capitalized in respect of development and production 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 June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Crude oil	**$ 239,491**	$ 123,970	**$ 439,987**	$ 253,056
Natural gas	**2,274**	1,025	**4,228**	2,018
Oil and natural gas sales	**$ 241,765**	$ 124,995	**$ 444,215**	$ 255,074

At June 30, 2018, receivables from contracts with customers, which are included in accounts receivable, were $52.8 million (December 31, 2017 - $28.4 million).

10. Net Finance Expense (Income)

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Bank charges and credit facility fees	**$ 584**	$ 792	**$ 1,004**	$ 1,701
Accretion on decommissioning and environmental liabilities	**1,087**	1,174	**2,307**	2,009
Interest and other income	**(953)**	(492)	**(1,498)**	(876)
Unrealized loss on foreign currency risk management contracts	**1,282**	—	**1,282**	—
Loss on settlement of decommissioning liabilities	**2,981**	—	**2,981**	—
Colombian net wealth tax	**—**	—	**—**	894
Net finance expense	**$ 4,981**	$ 1,474	**$ 6,076**	$ 3,728

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Non-cash finance expense	**$ 5,350**	$ 1,174	**$ 6,570**	$ 2,009
Cash finance expense	**(369)**	300	**(494)**	1,719
Net finance expense	**$ 4,981**	$ 1,474	**$ 6,076**	$ 3,728

11. Other Long-Term Liabilities

Other long-term liabilities are comprised of the following:

	June 30, 2018	December 31, 2017
Long-term SARs payable	**$ 2,309**	$ 1,250
Long-term DSUs payable	**4,135**	2,474
Long-term CRSUs payable	**2,066**	994
	$ 8,510	$ 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 (gain) loss	528	(412)	116
Balance, December 31, 2017	$ 36,774	$ 15,906	$ 52,680
Additions	3,542	993	4,535
Additions related to change in estimate	(178)	(118)	(296)
Settlements of obligations during the period	(3,843)	(84)	(3,927)
Loss on settlement of obligations	2,981	—	2,981
Accretion expense	1,287	1,020	2,307
Foreign exchange loss	478	30	508
Balance, June 30, 2018	**$ 41,041**	**$ 17,747**	**$ 58,788**
Current obligation	(3,555)	(6,590)	(10,145)
Long-term obligation	**$ 37,486**	**$ 11,157**	**$ 48,643**

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 June 30, 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 $73.5 million as at June 30, 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 $3.6 million (December 31, 2017 –$4.2 million) that is classified as a current obligation. During the six months ended June 30, 2018 the loss on settlement of obligations of $3.0 million primarily related to higher than expected abandonment costs on the El Eden block.

The total undiscounted amount of cash flows required to settle the Company's environmental liability is approximately $22.3 million as at June 30, 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 $6.6 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
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	2,889,797		13,884
Allocation of contributed surplus – exercise of options and RSUs	—		10,371
Repurchase of shares	(2,052,455)		(9,567)
Balance, June 30, 2018	**155,579,476**	**$**	**850,854**

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

In the six months ended June 30, 2018, a total of 2,889,797 options and RSUs were exercised for proceeds of $13.9 million (year ended December 31, 2017 - 2,328,239 options and RSUs were exercised for proceeds of $9.9 million).

In the six months ended June 30, 2018, the Company repurchased 2,052,455 common shares pursuant to its Normal Course Issuer Bid at a cost of $33.4 million (average cost per share of Cdn$21.08). 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 stock 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	193,650	18.52
Exercised	(2,257,039)	7.86
Forfeited	(7,200)	13.69
Balance, June 30, 2018	**4,408,846**	**13.12**

Stock options outstanding and the weighted average remaining life of the stock options at June 30, 2018 are as follows:

	Options outstanding				Options vested			
Exercise price Cdn$	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	843,934	1.30	$	9.86	843,934	1.30	$	9.86
$10.60 - $11.24	1,453,770	2.36	$	10.94	852,258	2.36	$	10.94
$11.25 - $15.59	123,859	2.84	$	13.87	46,775	1.43	$	12.65
$15.60 - $15.84	1,209,365	3.38	$	15.66	365,053	3.38	$	15.65
$15.85 - $18.53	777,918	3.91	$	16.66	188,861	3.68	$	16.05
	4,408,846	**2.72**	**$**	**13.12**	**2,296,881**	**2.22**	**$**	**11.75**

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 six months ended June 30,	**2018**	2017
Risk-free interest rate (%)	**1.93**	1.10
Expected life (years)	**4**	4
Expected volatility (%)	**43.29**	43.95
Forfeiture rate (%)	**3**	3
Expected dividends	**—**	—

The weighted average fair value at the grant date of options granted for the six months ended June 30, 2018 was Cdn$6.68 per option (six months ended June 30, 2017 - Cdn$5.64 per per option). The weighted average share price on the exercise date for options exercised in the six months ended June 30, 2018 was Cdn$19.40 (six months ended June 30, 2017 - Cdn$16.81).

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	537,025	0.01
Exercised	(632,758)	0.01
Forfeited	(7,467)	0.01
Balance, June 30, 2018	**2,627,095**	**0.01**

RSUs outstanding and the weighted average remaining life of the RSUs at June 30, 2018 are as follows:

	RSUs outstanding		RSUs vested	
Exercise price Cdn$	Number of RSUs	Weighted average remaining life (years)	Number of RSUs	Weighted average remaining life (years)
0.01	2,627,095	3.22	933,981	2.42

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 six months ended June 30, 2018 was Cdn$18.57 per RSU (six months ended June 30, 2017 - Cdn$15.99 per RSU). For the six months ended June 30, 2018 a weighted average forfeiture rate of 3% was applied (six months ended June 30, 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, December 31, 2016	—	—
Granted	103,500	0.01
Balance, December 31, 2017	103,500	0.01
Granted	217,000	0.01
Balance, June 30, 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 six months ended June 30, 2018 was Cdn$18.52 per PSU (six months ended June 30, 2017 - Cdn$16.01 per PSU).

d) Equity settled share-based compensation

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Option expense	**$ 842**	$ 1,873	**$ 1,801**	$ 3,830
Restricted and performance share units expense	**2,654**	3,172	**5,208**	5,941
Total	**$ 3,496**	$ 5,045	**7,009**	9,771

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	(693,176)	12.11
Forfeited	(48,527)	13.88
Balance, June 30, 2018	**1,646,304**	**13.90**

As at June 30, 2018, 289,994 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 six months ended June 30,	**2018**	2017
Risk-free interest rate (%)	**1.79**	1.34
Expected life (years)	**2**	4.6
Expected volatility (%)	**34**	43
Share price ($/Cdn)	**24.82**	14.75
Expected dividends	—	—

As at June 30, 2018, the total SARs liability accrued is $12.9 million (December 31, 2017 - $11.6 million) of which $2.3 million (December 31, 2017 - $1.2 million) is classified as long-term in accordance with the three year vesting period.

b) Deferred share units ("DSUs")

The Company has in place a deferred share unit plan pursuant to which the Company may grant deferred shares to all non-employee directors. The deferred share units vest immediately and are settled in cash upon the retirement of the non-employee director from the Parex Board. The value of the DSUs at the exercise date is equivalent to the five day weighted average share price at which the common shares of the Company traded for immediately preceding the exercise date. DSUs can only be redeemed following 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	—
Granted	48,475	—
Exercised on board retirement	(23,100)	—
Balance, June 30, 2018	**219,350**	—

The fair value at the grant date is equivalent to the five day weighted average share price at which the common shares of the Company traded for immediately preceding the grant date. The weighted average fair value at the grant date for the six months ended June 30, 2018 was Cdn $22.94 per DSU (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 June 30, 2018, the total DSUs liability accrued is $4.1 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 was 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	487,075	—
Exercised	(146,357)	—
Forfeited	(20,750)	—
Balance, June 30, 2018	**812,318**	**—**

As at June 30, 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 June 30, 2018, the total CRSUs liability accrued is $4.8 million (December 31, 2017 -$2.2 million) of which $2.1 million (December 31, 2017 - $1.0 million) is classified as long-term in accordance with the three year vesting period. For the six months ended June 30, 2018, Parex recorded $4.8 million of compensation costs related to the outstanding CRSUs (year ended December 31, 2017 – $2.2 million).

d) Cash settled share-based compensation

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
SARs expense (recovery)	**$ 5,426**	$ (1,944)	**$ 4,676**	$ (141)
DSUs expense	**119**	865	**1,653**	865
CRSUs expense	**4,847**	77	**4,834**	77
Total	**$ 10,392**	$ (1,002)	**$ 11,163**	$ 801

15. Income Tax

The components of tax expense for the three and six months ended June 30, 2018 and 2017 were as follows:

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Current tax expense	**$ 173,122**	$ 7,505	**$ 200,402**	$ 12,362
Deferred tax expense (recovery)	**(239,234)**	19,617	**(238,684)**	18,340
Tax expense (recovery)	**$ (66,112)**	$ 27,122	**$ (38,282)**	$ 30,702

The current and deferred tax (recovery) expense relates to the Company's operations in Colombia. Current tax in the three months ended June 30, 2018 was $173.1 million expense as compared to $7.5 million expense in the three months ended June 30, 2017. The increase in the current tax expense from the comparative period is a result of the voluntary tax restructuring completed in the three months ended June 30, 2018. Approximately $137.5 million relates to the voluntary tax restructuring while approximately $35.6 million relates to tax on Colombian cash flows in the three months ended June 30, 2018 as a result of the increase in oil prices driving higher taxable income.

Deferred tax in the three months ended June 30, 2018 was a recovery of $239.2 million ($19.6 million expense for the three months ended June 30, 2017). The main driver of the recovery of deferred tax was the voluntary tax restructuring completed in the quarter resulted in an increase in the tax basis of the Company's key assets.

16. Net Income per Share

a) Basic net income per share

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Net income				
Net income for the purpose of basic net income per share	**$188,601**	$ 3,524	**$ 260,113**	$ 43,630
Weighted average number of shares for the purposes of basic net income per share (000s)	**155,771**	154,249	**155,406**	153,769
Basic net income per share	**$ 1.21**	$ 0.02	**$ 1.67**	$ 0.28

b) Diluted net income per share

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Net income				
Net income used to calculate diluted net income per share	**$188,601**	$ 3,524	**$ 260,113**	$ 43,630
Weighted average number of shares for the purposes of basic net income per share (000s)	**155,771**	154,249	**155,406**	153,769
Dilutive effect of stock options, RSUs and PSUs on potential common shares	**4,553**	3,814	**4,152**	3,564
Weighted average number of shares for the purposes of diluted net income per share	**160,324**	158,063	**159,558**	157,333
Diluted net income per share	**$ 1.18**	$ 0.02	**$ 1.63**	$ 0.28

For the three and six months ended June 30, 2018, no stock options were excluded from the diluted weighted average shares calculation (three and six months ended June 30, 2017 - 18,750 stock options excluded as they were anti-dilutive).

17. Supplemental Disclosure of Cash Flow Information

a) Net change in non-cash working capital

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Accounts receivable	**$ (36,610)**	$ 2,971	**$ (45,181)**	$ (17,438)
Prepaids and other current assets	**(3,235)**	(638)	**(5,290)**	(454)
Oil inventory	**(899)**	(1,194)	**(1,663)**	1,550
Accounts payable and accrued liabilities	**202,964**	22,041	**233,255**	40,285
Depletion related to oil inventory	**194**	336	**583**	(409)
Net change in non-cash working capital	**$ 162,414**	$ 23,516	**$ 181,704**	$ 23,534
Operating	**$ 102,368**	$ 28,041	**$ 114,160**	$ 13,506
Investing	**60,046**	(4,525)	**67,544**	10,028
Financing	**—**	—	**—**	—
Net change in non-cash working capital	**$ 162,414**	$ 23,516	**$ 181,704**	$ 23,534

b) Interest and taxes paid

	For the three months ended June 30,		For the six months ended June 30,	
	2018	**2017**	**2018**	2017
Cash interest paid	**$ —**	**$ 6**	**$ 1**	$ 27
Cash income taxes paid	**$ 14,528**	**$ 2,180**	**$ 14,838**	$ 2,180

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.

Parex has a senior secured credit facility which as at June 30, 2018 had a borrowing base in the amount of $100.0 million (December 31, 2017 - $100.0 million). The credit facility is intended to serve as means to increase liquidity and fund cash needs as they arise. As at June 30, 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 21 - Commitments). This performance guarantee facility has a limit of $250.0 million (December 31, 2017 - limit of $250.0 million) of which $101.3 million (December 31, 2017 - $116.1 million) is utilized at June 30, 2018. At June 30, 2018, there is an additional $26.5 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 June 30, 2018, the Company's net working capital surplus was $66.1 million (December 31, 2017 - $163.4 million), of which $323.1 million is cash.

Parex has the ability to adjust its capital structure by issuing new equity or debt and making adjustments to its capital expenditure program to the extent the capital expenditures are not committed. The Company considers its capital structure at this time to include shareholders' equity and the credit facility. As at June 30, 2018 shareholders' equity was $1,135.9 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 June 30, 2018 had the majority of its oil sales to 10 counterparties. Accounts receivable balance as at June 30, 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 June 30, 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 June 30, 2018 was $nil.

The following are the contractual maturities of financial liabilities at June 30, 2018:

	Less than 1 year	2-3 Years	4-5 Years	Thereafter	Total
Accounts payable and accrued liabilities [1]	$ 175,317	—	—	—	$ 175,317
Current income tax payable	194,678	—	—	—	194,678
Cash settled equity plans payable	13,390	8,510	—	—	21,900
Total	**$ 383,385**	**8,510**	**—**	**—**	**$ 391,895**

[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
Current income tax payable	42,266	—	—	—	42,266
Cash settled equity plans payable	11,889	4,718	—	—	16,607
Total	**$ 145,891**	**4,718**	**—**	**—**	**$ 150,609**

[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 primarily sold under short-term contracts, exposing it to the risk of near-term price movements.

As at June 30, 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 six months ended June 30, 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 June 30, 2018 is a $0.5 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 (gain) loss on the commodity risk management contracts:

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Realized (gain) on commodity risk management contracts	**$ —**	$ (361)	**$ —**	$ (361)
Premiums paid on commodity risk management contracts	**364**	—	**544**	1,189
Unrealized (gain) loss on commodity risk management contracts	**26**	(730)	**242**	(3,237)
Total	**$ 390**	$ (1,091)	**$ 786**	$ (2,409)

As shown in the table above, as at June 30, 2018, Parex had committed to the future sale of 920,000 barrels of oil with put spreads from Brent oil prices of $50.00 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 June 30, 2018:

	Brent Price	**Impact for the six months ended June 30, 2018**	
		Increase of $10/bbl	Decrease of $10/bbl
Oil hedged contract loss (gain)	Period end	**$ —**	$ **(10)**

d) Foreign currency risk

The Company is exposed to foreign currency risk as various portions of its cash balances are held in Canadian dollars (Cdn$) and Colombian pesos (COP$) while its committed capital expenditures are expected to be primarily denominated in US dollars.

The following is a summary of the foreign currency risk management contracts in place as at June 30, 2018:

Period Hedged	Reference	Currency Option Type	Amount USD	Strike Price COP
April 25, 2018 to April 25, 2019	Colombian Peso	Costless Collar	$20,000,000	2,700-3,025
June 28, 2018 to April 25, 2019	Colombian Peso	Costless Collar	$60,000,000	2,750-3,160

The table below summarizes the loss on the foreign currency risk management contracts:

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Unrealized loss on foreign currency risk management contracts	**$ 1,282**	$ —	**$ 1,282**	$ —
Total	**$ 1,282**	$ —	**$ 1,282**	$ —

The fair value of the foreign currency risk management contracts is recorded in the financial statement line item "Derivative financial instruments" in the consolidated balance sheet.

The Company recorded a $1.3 million loss on these contracts in the three months ended June 30, 2018 which is recorded in the financial statement line item "Finance expense" in the consolidated statements of comprehensive income. Refer to note 10.

The following sensitivity show the resulting unrealized loss (gain) and impact on net income before tax for the foreign exchange risk management contracts for the respective changes in the period end foreign exchange rates at June 30, 2018:

	Brent Price	Impact for the six months ended June 30, 2018	
		Appreciation of COP 10%	Depreciation of COP 10%
Exchange Rate USD/COP	Period end	**$ (5,181)**	**$ 4,068**

Subsequent to June 30, 2018, the Company entered into the following foreign currency risk management contract:

Period Hedged	Reference	Currency Option Type	Amount USD	Strike Price COP
July 24, 2018 to July 25, 2019	Colombian Peso	Costless Collar	$60,000,000	2,750-3,100

20. Segmented Information

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

For the three months ended June 30, 2018 (unaudited)	Canada	Colombia	Total
Oil and natural gas sales	$ —	$ 241,765	$ 241,765
Royalties	—	(31,177)	(31,177)
Revenue	—	210,588	210,588
Commodity risk management contracts (loss)	—	(390)	(390)
	—	210,198	210,198
Expenses			
Production	—	22,193	22,193
Transportation	—	12,200	12,200
Purchased oil	—	3,167	3,167
General and administrative	3,473	4,457	7,930
Equity settled share-based compensation	3,496	—	3,496
Cash settled share-based compensation	1,666	8,726	10,392
Depletion, depreciation and amortization	38	24,180	24,218
Foreign exchange (gain) loss	324	(1,192)	(868)
	8,997	73,731	82,728
Finance (income)	(160)	(793)	(953)
Finance expense	247	5,687	5,934
Net finance expense	87	4,894	4,981
Income (loss) before taxes	$ (9,084)	$ 131,573	$ 122,489
Current tax expense	—	173,122	173,122
Deferred tax expense	—	(239,234)	(239,234)
Net income (loss)	**$ (9,084)**	**$ 197,685**	**$ 188,601**
Capital assets (end of period)	$ 253	$ 824,104	$ 824,357
Capital expenditures	$ 77	$ 100,490	$ 100,567
Total assets (end of period)	$ 69,948	$ 1,516,301	$ 1,586,249

For the three months ended June 30, 2017 (unaudited)		Canada		Colombia		Total
Oil and natural gas sales	$	—	$	124,995	$	124,995
Royalties		—		(12,421)		(12,421)
Revenue		—		112,574		112,574
Commodity risk management contracts gain		—		1,091		1,091
		—		113,665		113,665
Expenses						
Production		—		16,363		16,363
Transportation		—		13,449		13,449
Purchased oil		—		912		912
General and administrative		2,539		5,860		8,399
Legal settlement		15,000		—		15,000
Equity settled share-based compensation		5,045		—		5,045
Cash settled share-based compensation		863		(1,865)		(1,002)
Depletion, depreciation and amortization		46		25,860		25,906
Foreign exchange (gain)		(55)		(2,472)		(2,527)
		23,438		58,107		81,545
Finance (income)		(177)		(315)		(492)
Finance expense		511		1,455		1,966
Net finance expense		334		1,140		1,474
Income (loss) before taxes	$	(23,772)	$	54,418	$	30,646
Current tax expense		—		7,505		7,505
Deferred tax expense		—		19,617		19,617
Net income (loss)	**$**	**(23,772)**	**$**	**27,296**	**$**	**3,524**
Capital assets (end of period)	$	317	$	667,527	$	667,844
Capital expenditures	$	—	$	59,008	$	59,008
Total assets (end of period)	$	91,124	$	924,416	$	1,015,540

For the six months ended June 30, 2018 (unaudited)		Canada		Colombia		Total
Oil and natural gas sales	$	—	$	444,215	$	444,215
Royalties		—		(57,356)		(57,356)
Revenue		—		386,859		386,859
Commodity risk management contracts (loss)		—		(786)		(786)
		—		386,073		386,073
Expenses						
Production		—		41,395		41,395
Transportation		—		27,543		27,543
Purchased oil		—		4,603		4,603
General and administrative		6,423		9,662		16,085
Equity settled share-based compensation		7,009		—		7,009
Cash settled share-based compensation		1,653		9,510		11,163
Depletion, depreciation and amortization		73		46,584		46,657
Foreign exchange loss		297		3,414		3,711
		15,455		142,711		158,166
Finance (income)		(339)		(1,159)		(1,498)
Finance expense		387		7,187		7,574
Net finance expense		48		6,028		6,076
Income (loss) before taxes		(15,503)		237,334		221,831
Current tax expense		—		200,402		200,402
Deferred tax expense		—		(238,684)		(238,684)
Net income (loss)	**$**	**(15,503)**	**$**	**275,616**	**$**	**260,113**
Capital assets (end of period)	$	253	$	824,104	$	824,357
Capital expenditures	$	79	$	158,698	$	158,777
Total assets (end of period)	$	69,948	$	1,516,301	$	1,586,249

For the six months ended June 30, 2017 (unaudited)		Canada		Colombia		Total
Oil and natural gas sales	$	—	$	255,074	$	255,074
Royalties		—		(25,673)		(25,673)
Revenue		—		229,401		229,401
Commodity risk management contracts gain		—		2,409		2,409
		—		231,810		231,810
Expenses						
Production		—		31,752		31,752
Transportation		—		27,629		27,629
Purchased oil		—		3,286		3,286
General and administrative		5,391		10,748		16,139
Legal settlement		15,000		—		15,000
Equity settled share-based compensation		9,771		—		9,771
Cash settled share-based compensation		863		(62)		801
Depletion, depreciation and amortization		92		50,223		50,315
Foreign exchange (gain) loss		27		(970)		(943)
		31,144		122,606		153,750
Finance (income)		(319)		(557)		(876)
Finance expense		815		3,789		4,604
Net finance expense		496		3,232		3,728
Income (loss) before taxes		(31,640)		105,972		74,332
Current tax expense		—		12,362		12,362
Deferred tax expense		—		18,340		18,340
Net income (loss)	**$**	**(31,640)**	**$**	**75,270**	**$**	**43,630**
Capital assets (end of period)	$	317	$	667,527	$	667,844
Capital expenditures	$	24	$	94,547	$	94,571
Total assets (end of period)	$	91,124	$	924,416	$	1,015,540

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

21. Commitments

a) Colombia

At June 30, 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 $127.8 million (December 31, 2017 - $142.6 million) to support the exploration work commitments in respect of the 20 blocks in Colombia.

At June 30, 2018, EDC has provided the Company's bank with performance security guarantees to support approximately $101.3 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 favor of EDC. At June 30, 2018, there is an additional $26.5 million (December 31, 2017 - $26.4 million) of letters of credit that are provided by a Latin American bank on an unsecured basis. Letters of credit issued to the ANH and Ecopetrol are reduced from time to time to reflect completed work on an ongoing basis.

The value of the Company's exploration commitments as at June 30, 2018 in respect of the Colombia blocks are estimated to be as follows:

2018	$	17,199
2019		130,028
Thereafter		—
	$	**147,227**

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 June 30, 2018 are as follows:

		Total	2018	2019	2020	2021	Thereafter
Office and accommodations	$	12,123	1,535	2,001	2,066	1,787	4,734

22. Subsequent Event

On July 17, 2018 the Company announced that its Board of Directors have determined it is timely, prudent and in the best interests of the Company to initiate a formal process to explore, review and evaluate strategic repositioning alternatives with a view to enhancing shareholder value.

The strategic repositioning review will focus on the potential sale of the Company's Southern Casanare ("SoCa") assets (LLA-32, LLA-34 and Cabrestero), the retention of its exploration assets and the return of the net sale proceeds to shareholders. Consideration will also be given to a corporate sale or other strategic actions that would result in the creation of additional value for shareholders. This review of strategic repositioning alternatives may result in no specific transaction being pursued, with the Company continuing its operations as they currently exist with a focus on sustainable self-funded growth.

Parex has not set a definitive schedule to complete its identification, examination and consideration of strategic repositioning alternatives or made a decision to pursue any particular strategic repositioning alternative. The review process was not initiated as a result of receiving any transaction proposal. Given the nature of the process and the need for confidentiality during the process, the Company does not intend to provide updates until such time as the Board of Directors approves a definitive transaction or strategic repositioning alternative, or otherwise determines that further disclosure is necessary or appropriate. The Company cautions that there are no guarantees that the review of strategic repositioning alternatives will result in a transaction, or, if a transaction is undertaken, as to its terms, timing or conditions or approvals required to implement such transaction.

As a result of the strategic repositioning alternatives review process, Parex terminated its automatic share purchase plan to purchase up to 3,000,000 of its common shares pursuant to the Company's normal course issuer bid.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of Parex Resources Inc. ("Parex" or "the Company") for the period ended June 30, 2018 is dated August 8, 2018 and should be read in conjunction with the Company's unaudited condensed interim consolidated financial statements for the period ended June 30, 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 2,144,555 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 20 for the Advisory on Forward-Looking Statements and page 22 for Non-GAAP Terms used.

Three months ended June 30, 2018 ("second quarter or Q2") Highlights

- Quarterly production was 42,625 boe/d (99% crude oil), representing an increase of 5 percent over the previous quarter ended March 31, 2018 and an increase of 24 percent over the three months ended June 30, 2017;
- Earned net income of $188.6 million ($1.21 per share basic) compared to a net income of $3.5 million ($0.02 per share basic) in the three months ended June 30, 2017. For the first six months of 2018 Parex has earned $260.1 million of net income;
- A voluntary tax restructuring with a cost of $137.5 million was completed in the quarter generating additional income of $239.2 million for a net income benefit in the quarter of $101.7 million. For the first six months of 2018 Parex has earned $260.1 million of net income;
- Generated adjusted funds flow from operations of $121.7 million ($0.78 per share basic) which has been adjusted to exclude the $137.5 million ($0.88 per share basic) previously released cost of a voluntary tax restructuring completed in June 2018 which will be funded from existing working capital;
- Including the $137.5 million voluntary tax restructuring cost, funds flow from operations was $(15.8) million ($0.10 loss per share basic) as compared to $0.34 per share for the three months ended June 30, 2017 and $0.65 per share for the three months ended March 31, 2018;
- Capital expenditures were $100.6 million in the period compared to $59.0 million in the three months ended June 30, 2017. 2018 year to date capital expenditures are $158.8 million;
- Working capital was $66.1 million at June 30, 2018 compared to $205.8 million at March 31, 2018 and $128.3 million at June 30, 2017. The Company has an undrawn bank credit facility of $100.0 million; and
- Participated in drilling 18 wells in Colombia resulting in 10 oil wells, 1 disposal and 7 untested wells.

Financial Summary

(Financial figures in 000s except per share amounts)	For the three months ended June 30, 2018	2017	For the six months ended June 30, 2018	2017
Average daily production (bopd)	**42,052**	34,013	**41,063**	33,176
Average daily natural gas production (mcf/d)	**3,438**	1,668	**3,294**	1,656
Average oil and natural gas production (boe/d)	**42,625**	34,291	**41,612**	33,452
Production split (% crude oil)	**99**	99	**99**	99
Average realized sales price ($/boe)	**61.96**	40.26	**59.08**	41.23
Operating netback ($/boe) [1]	**44.97**	26.59	**42.15**	27.35
Oil and natural gas sales	**241,765**	124,995	**444,215**	255,074
Funds flow (used in) provided by operations[4]	**(15,765)**	51,763	**85,136**	119,669
Per share – basic	**(0.10)**	0.34	**0.55**	0.78
Per share – diluted [1]	**(0.10)**	0.33	**0.53**	0.76
Net income	**188,601**	3,524	**260,113**	43,630
Per share – basic	**1.21**	0.02	**1.67**	0.28
Per share – diluted	**1.18**	0.02	**1.63**	0.28
Capital Expenditures	**100,567**	59,008	**158,777**	94,571
Total assets (end of period)	**1,586,249**	1,015,540	**1,586,249**	1,015,540
Working capital surplus (end of period)[2]	**66,050**	128,347	**66,050**	128,347
Bank debt (end of period)[3]	**-**	-	**-**	-
Weighted average shares outstanding (000s)				
Basic	**155,771**	154,249	**155,406**	153,769
Diluted	**160,324**	158,063	**159,558**	157,333
Outstanding shares (end of period (000s)	**155,579**	154,377	**155,579**	154,377

(1) Non-GAAP term. See "Non-GAAP Terms".
(2) Working capital calculation does not take into consideration the undrawn amount available under the syndicated bank credit facility.
(3) Syndicated bank credit facility borrowing base of $100.0 million as at June 30, 2018 and 2017.
(4) For the three and six months ended June 30, 2018, funds flow provided by operations includes a $137.5 million ($0.88 per share basic) charge for a voluntary tax restructuring, refer to the "Income Tax" section. For the three and six months ended June 30, 2017, funds flow provided by operations includes a $15.0 million ($0.09 per share basic) charge for a one time legal settlement.

Strategy

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

Principal Properties

As at June 30, 2018 the Company's principal land holdings and interests in exploration and production blocks held by its subsidiaries were as follows:

	Working Interest	Gross Acres	Net Acres
Colombia Llanos Basin			
Operated Properties			
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
CPO-11(1)	50 %	570,276	285,138
Non-Operated Properties			
LLA-34	55 %	68,382	37,610
Balay	10 %	4,500	450
Colombia Magdalena Basin			
Operated Properties			
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		2,144,555	1,575,170

(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.

Guidance Update: Q4 2018 Production to Average 48,000 boe/d

Q3 2018 production is expected to average above 44,000 boe/d and Q4 2018 production is forecast to average 48,000 boe/d, an increase of 2,000 bopd from the original guidance. The full year 2018 capital expenditures mid-point forecast has been increased to approximately $325 million from prior guidance of $280 million. The increase capital expenditures is primarily due to:

- the drilling a total of 16 additional gross oil wells and injection wells on blocks LLA-34 and Cabrestero in 2018, and
- drilling/seismic on the newly acquired CPO-11 Block.

Increased production in Q4 2018 does not reflect production response due to injection wells drilled at Cabrestero in 2018 and which is expected to increase production in Q1 2019.

	Previous	Revised
Total average annual production (boe/d) (boe/d, 99% oil)	41,000-43,000	43,000-44,000
Capital Expenditures ($millions)	$270-$290	$320-$330

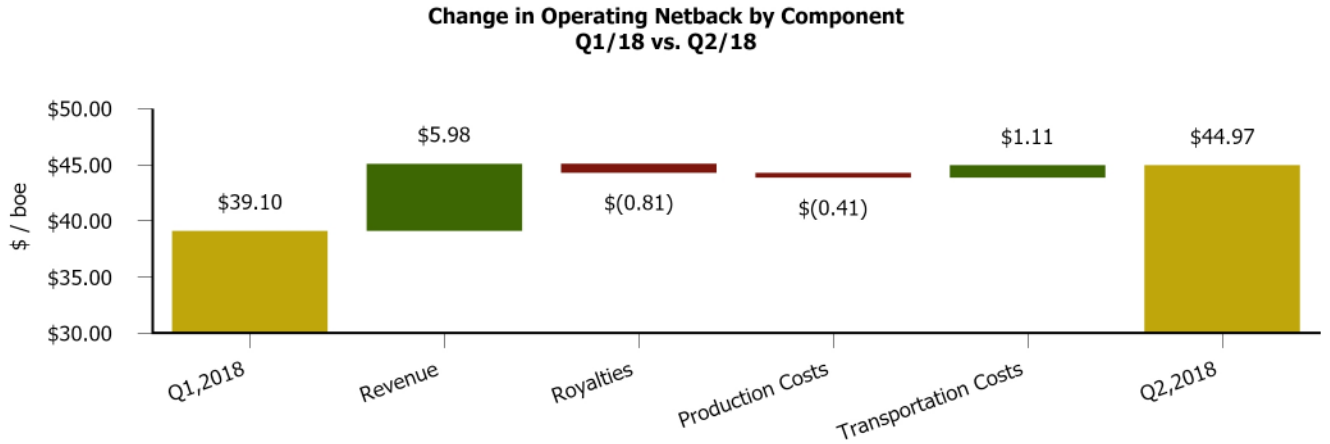
Financial and Operational Results

Consolidated Results of Operations

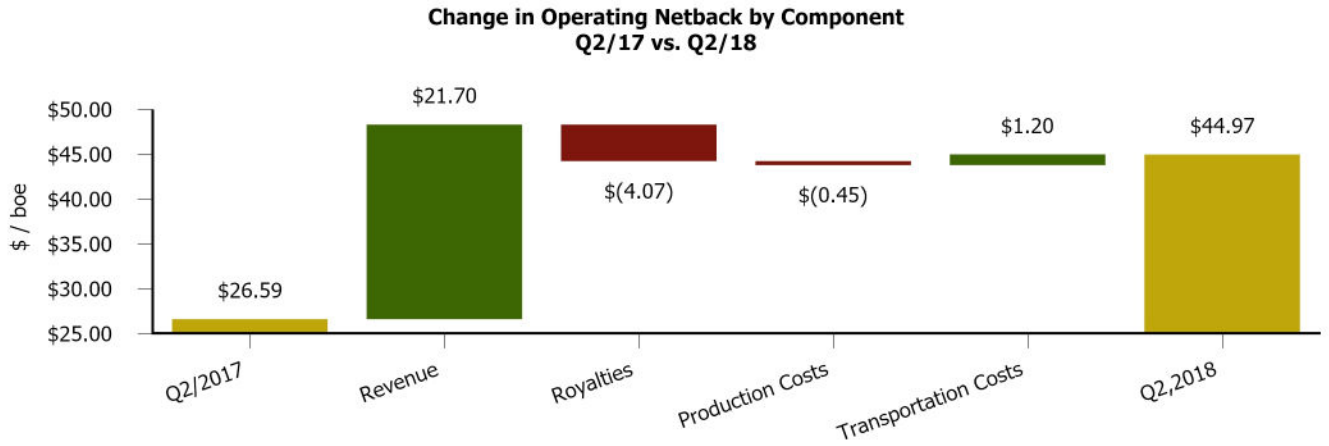
Parex' operations are conducted in Colombia and Canada which are the Company's reportable segments.

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Average daily production				
Colombia – oil (bbl/d)	**42,052**	34,013	**41,063**	33,176
Colombia – natural gas (mcf/d)	**3,438**	1,668	**3,294**	1,656
Total (boe/d)	**42,625**	34,291	**41,612**	33,452
Production split (% crude oil production)	**99**	99	**99**	99
Average daily sales of oil and natural gas				
Colombia – produced oil (bbl/d)	**41,734**	33,563	**40,563**	33,442
Colombia – purchased oil (bbl/d)	**571**	275	**429**	465
Colombia – produced natural gas (Mcf/d)	**3,438**	1,668	**3,294**	1,656
Total (boe/d)	**42,878**	34,116	**41,541**	34,183
Operating netback ($000s)[1]				
Oil and natural gas sales	**$ 241,765**	$ 124,995	**$ 444,215**	$ 255,074
Royalties	**(31,177)**	(12,421)	**(57,356)**	(25,673)
Net revenue	**210,588**	112,574	**386,859**	229,401
Production expense	**(22,193)**	(16,363)	**(41,395)**	(31,752)
Transportation expense	**(12,200)**	(13,449)	**(27,543)**	(27,629)
Purchased oil	**(3,167)**	(912)	**(4,603)**	(3,286)
Operating netback	**$ 173,028**	$ 81,850	**$ 313,318**	$ 166,734
Operating netback (per boe)[1]				
Oil and natural gas sales	**$ 61.96**	$ 40.26	**$ 59.08**	$ 41.23
Royalties	**(8.10)**	(4.03)	**(7.71)**	(4.21)
Net revenue	**53.86**	36.23	**51.37**	37.02
Production expense	**(5.76)**	(5.31)	**(5.56)**	(5.20)
Transportation expense	**(3.13)**	(4.33)	**(3.66)**	(4.47)
Operating netback	**$ 44.97**	$ 26.59	**$ 42.15**	$ 27.35

[1] Refer to page 22 "Non-GAAP Terms" for a description and details of the operating netback calculation.



Overall, the Company's benchmark Brent price increased by $7.70/bbl in the second quarter as compared to the first quarter of 2018, while the operating netback increased by $5.87/boe. The decrease in the operating netback on a relative basis compared to the Brent crude price increase is mainly a result of royalties increasing from $7.29/boe in Q1 2018 to $8.10/boe in Q2 2018 due to an increase in the price of crude oil. Also impacting revenue and transportation costs was a change in the mix of oil sale contracts resulting in an increase in differential from Brent crude prices with a corresponding reduction in transportation costs as more wellhead sale contracts were utilized in Q2 2018.



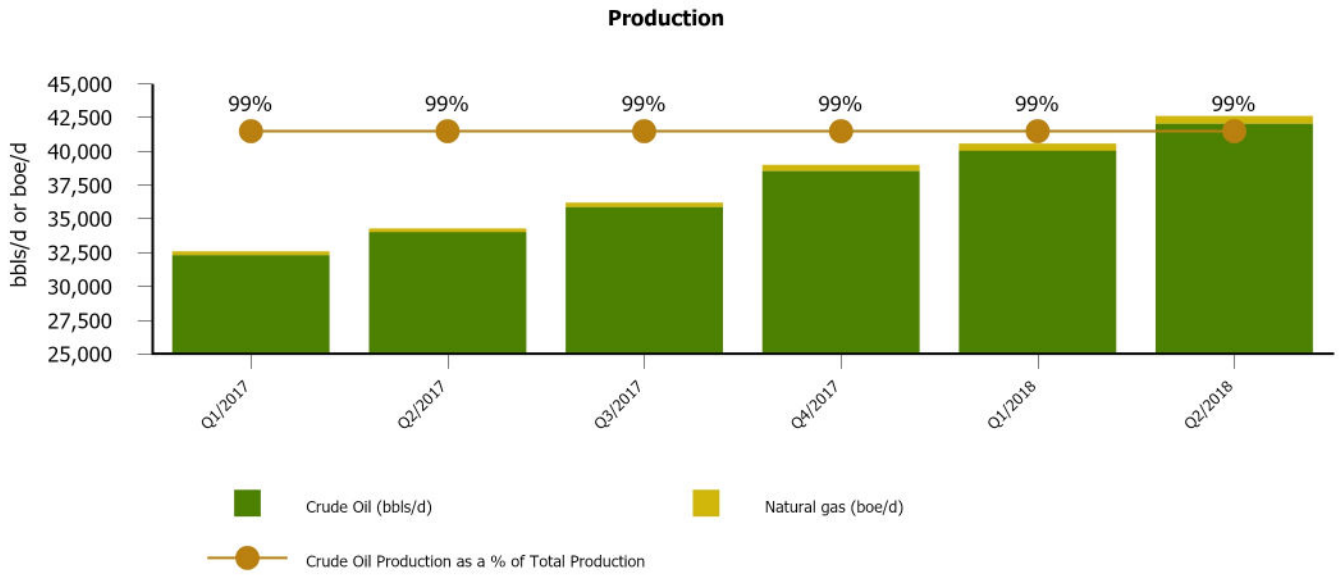
Overall, the Company's benchmark Brent price increased by $24.10/boe in the second quarter of 2018 as compared to the second quarter of 2017, while the operating netback increased by $18.38/boe. The decrease in operating netback on a relative basis compared to the Brent crude increase is mainly a result of an increase in royalties in Q2 2018 as a result of higher crude oil benchmark prices.

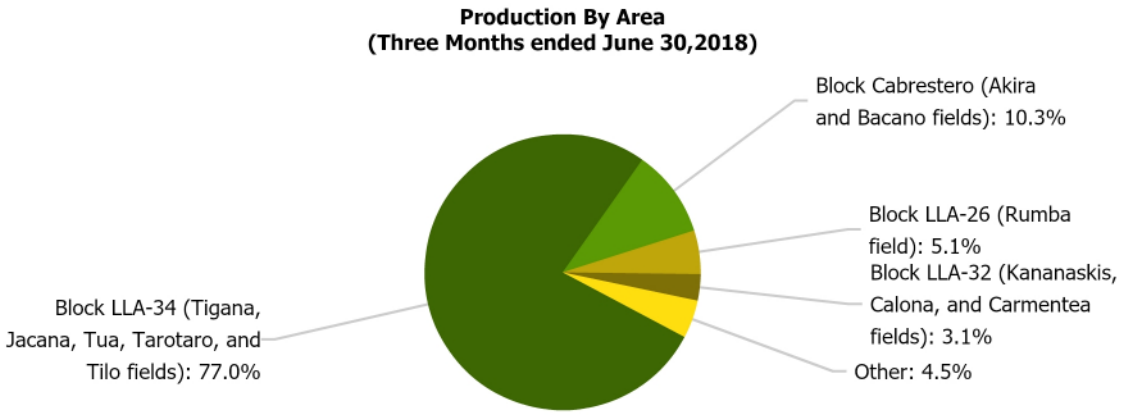
2018 Colombian Oil and Natural Gas Sales

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

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Block LLA-34 (Tigana, Jacana, Tua, Tarotaro, and Tilo fields)	**32,383**	24,314	**31,287**	23,366
Block Cabrestero (Akira and Bacano fields)	**4,333**	3,557	**4,251**	3,039
Block LLA-26 (Rumba field)	**2,147**	3,701	**2,197**	3,773
Block LLA-32 (Kananaskis, Calona, and Carmentea fields)	**1,303**	961	**1,161**	986
Other	**1,886**	1,480	**2,167**	2,012
Total Crude Oil Production	**42,052**	34,013	**41,063**	33,176
Natural gas production	**573**	278	**549**	276
Total crude oil and natural gas production	**42,625**	34,291	**41,612**	33,452
Crude oil inventory (build) draw	**(318)**	(450)	**(500)**	266
Average daily sales of produced oil and natural gas	**42,307**	33,841	**41,112**	33,718
Purchased oil	**571**	275	**429**	465
Sales Volumes	**42,878**	34,116	**41,541**	34,183

Oil and natural gas production for the second quarter of 2018 averaged 42,625 boe/d, an increase of approximately 24 percent from the comparative second quarter of 2017, and an increase of approximately 5 percent over the first quarter of 2018. Oil and natural gas sales in the second quarter of 2018 were 42,878 boe/d compared to 34,116 boe/d for the three months ended June 30, 2017. The increase in oil sales was primarily a result of the increase in oil production over the comparative period.





b) Impact of Accounting Policy Change

On January 1, 2018 Parex adopted a new accounting policy that changed 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 three and six months ended June 30, 2018 as well as the impact of the change on the comparative three and six months ended June 30, 2017:

For the three months ended June 30, 2018 and 2017:

		Upon accounting policy change	**As previously released**
	For the 3 months ended June 30, 2018	For the 3 months ended June 30, 2017	For the 3 months ended June 30, 2017
Realized price differential to Brent ($/boe)	**(12.76)**	(10.60)	(4.03)
Transportation expense ($/boe)	**(3.13)**	(4.34)	(10.91)
Total differential plus transportation expense ($/boe)	**(15.89)**	(14.94)	(14.94)

For the six months ended June 30, 2018 and 2017:

		Upon accounting policy change	As previously released
	For the 6 months ended June 30, 2018	For the 6 months ended June 30, 2017	For the 6 months ended June 30, 2017
Realized price differential to Brent ($/boe)	**(12.04)**	(11.51)	(4.97)
Transportation expense ($/boe)	**(3.66)**	(4.47)	(11.01)
Total differential plus transportation expense ($/boe)	**(15.70)**	(15.98)	(15.98)

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 expense 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 June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Reference Prices				
Brent ($/bbl)	**74.97**	50.87	**71.12**	52.74
Vasconia ($/bbl)	**70.47**	47.10	**66.67**	48.34
WTI ($/bbl)	**67.97**	48.21	**65.43**	49.99
Average Realized Prices				
Realized sales price ($/bbl)	**62.21**	40.26	**59.08**	41.23
Realized oil hedging (loss)gain ($/bbl)	**(0.09)**	0.12	**(0.07)**	(0.13)
Realized price after hedging ($/bbl)	**62.12**	40.38	**59.01**	41.10
Realized price differential to Brent crude ($/bbl)	**(12.76)**	(10.61)	**(12.04)**	(11.51)

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

Average price for the period	**Q2 2018**	Q1 2018	Q4 2017	Q3 2017	Q2 2017
Brent ($/bbl)	**74.97**	67.27	61.46	52.17	50.87
Vasconia ($/bbl)	**70.47**	62.87	57.30	49.15	47.10
Vasconia ($/bbl) differential	**(4.50)**	(4.40)	(4.16)	(3.02)	(3.77)
Parex quality differential ($/bbl)	**(0.71)**	(0.24)	(0.40)	(1.08)	(0.26)
Parex adjustment on certain oil sale contracts ($/bbl) (1)	**(7.55)**	(6.46)	(6.47)	(6.91)	(6.58)
Parex realized sales price ($/bbl)	**62.21**	56.17	50.43	41.16	40.26
Parex realized price (differential) to Brent crude ($/bbl)	**(12.76)**	(11.10)	(11.03)	(11.01)	(10.61)
Parex realized price (differential) to Vasconia crude ($/bbl)	**(8.26)**	(6.70)	(6.87)	(7.99)	(6.84)

(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 6.

d) Natural Gas Revenue and Realized Prices

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Revenue (000's)	**$ 2,274**	$ 1,025	**$ 4,228**	$ 2,018
Realized sales price ($/Mcf)	**7.27**	6.75	**7.09**	6.73

e) Oil and Natural Gas Revenue

Second quarter 2018 oil revenue increased $116.8 million or 93 percent as reconciled in the table below to the second quarter of 2017:

(000s)		
Oil and natural gas revenue, three months ended June 30, 2017	$	**124,995**
Sales volume of produced oil an increase of 22% (7,615 bopd)		**27,899**
Sales volume of purchased oil, an increase of 108% (296 bopd)		**1,084**
Oil sales price increase of 54%		**85,515**
Sales volume and price change of produced natural gas, an increase of		**2,272**
Oil and natural gas revenue, three months ended June 30, 2018	**$**	**241,765**

Oil revenue increased in the three months ended June 30, 2018 compared to the same period in 2017 mainly due to the increase in world oil prices and increased sales volumes of produced oil.

f) Colombian Crude Oil Inventory in Transit

As at June 30, ($000s)		**2018**		2017
Crude oil in transit	**$**	**4,701**	$	1,284

As at June 30, 2018, the Company had 193.7 mbbls of crude oil inventory in transit, which was injected into the Colombian pipelines. The inventory was valued based on direct and indirect expenditures (including production costs, certain transportation costs, depletion expense and royalty expense) at approximately $24/bbl ($29/bbl - 2017) incurred in bringing the crude oil to its existing condition and location.

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

For the periods ended (mbbls)	**June 30, 2018**	March 31, 2018	Dec. 31, 2017	Sept. 30, 2017
Crude oil inventory in transit - beginning of the period	**164.8**	103.0	70.9	44.1
Oil production	**3,826.7**	3,605.7	3,546.8	3,301.7
Oil sales	**(3,849.7)**	(3,569.7)	(3,542.2)	(3,298.8)
Purchased oil	**51.9**	25.8	27.5	23.9
Crude oil inventory in transit - end of the period	**193.7**	164.8	103.0	70.9
% of period production	**5.1**	4.6	2.9	2.1

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

g) Purchased Oil

	For the three months ended June 30,				For the six months ended June 30,			
		2018		2017		**2018**		2017
Purchased oil expense ($000s)	**$**	**3,167**	$	912	**$**	**4,603**	$	3,286

Purchased oil expense for the three and six months ended June 30, 2018 was $3.2 million and $4.6 million compared to $0.9 million and $3.3 million for the 2017 three and six month comparative periods. Transportation costs are incurred by the Company to transport purchased oil to sale delivery points.

Colombian Royalties

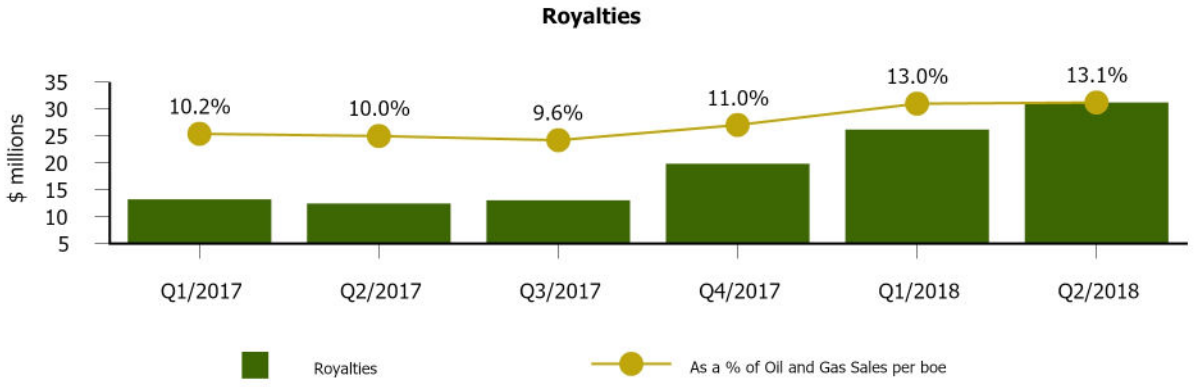
	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Royalties ($000s)	**$ 31,177**	$ 12,421	**$ 57,356**	$ 25,673
Per unit ($/boe)	**8.10**	4.03	**7.71**	4.21
Percentage of sales[1]	**13.1%**	10.0%	**13.0%**	10.2%

[1] Calculated based on Company working interest sales volumes excluding purchased oil volumes sold.

In the three and six months ended June 30, 2018 royalties as a percentage of sales were 13.1% and 13.0% compared to 13.0% during the three months ended March 31, 2018 and 10.0% and 10.2% in the three and six month ended June 30, 2017.

The increase in royalties as a percentage of sales compared to the comparative periods 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. 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.



Colombian Production Expense

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Production expense (000s)	**$ 22,193**	$ 16,363	**$ 41,395**	$ 31,752
Per unit ($/boe)[1]	**5.76**	5.31	**5.56**	5.20

[1] Calculated based on Company working interest sales volumes excluding purchased oil volumes sold.

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

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Per unit ($/boe) – based on sales volumes – operated[1]	**7.73**	7.80	**8.47**	7.88
Per unit ($/boe) – based on sales volumes – non-operated[1]	**5.03**	4.42	**4.57**	4.17

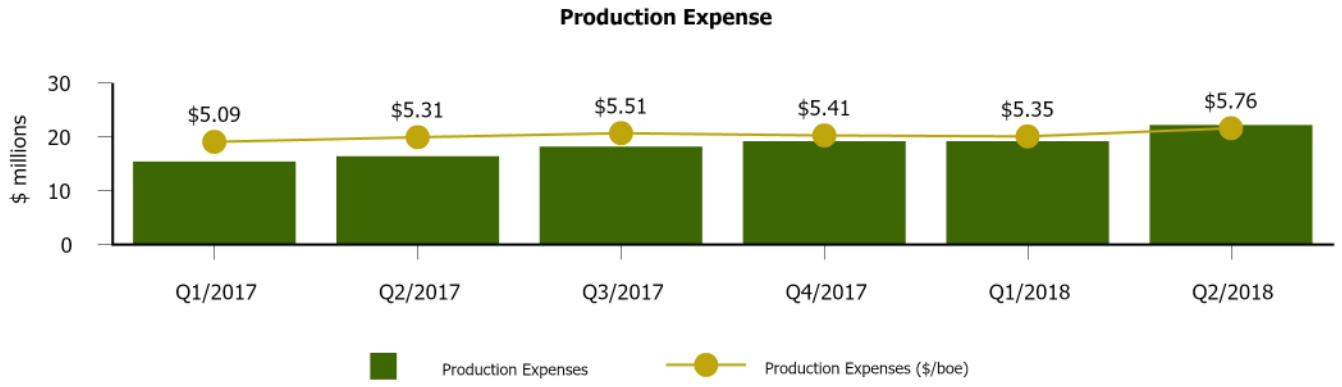
[1] Calculated based on Company working interest sales volumes excluding purchased oil volumes sold.

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

Production expense for the three and six months ended June 30, 2018 was $5.76/boe and $5.56/boe compared to $5.31/boe and $5.20/boe in the three and six months ended June 30, 2017. Production expense for the first quarter of 2018 was $5.35/boe. Operated properties production expense in the second quarter of 2018 was $7.73/boe compared to $9.37/boe for the first quarter of 2018 and non-operated properties production expense in the second quarter of 2018 was $5.03/boe compared to $4.10/boe for the first quarter of 2018. The increase in operated production

expense for the six months ended June 30, 2018 is a result of managing production on operated fields which resulted in decreased fixed cost absorption on operated fields. The increase in non-operated production expense in the three month period is a result of increased workovers on Block LLA-34 over the comparative period.

The overall slight increase in production expense on a per boe basis in Q2 2018 over Q1 2018 is mainly a result of an increase in the number of well workovers on Block LLA-34.



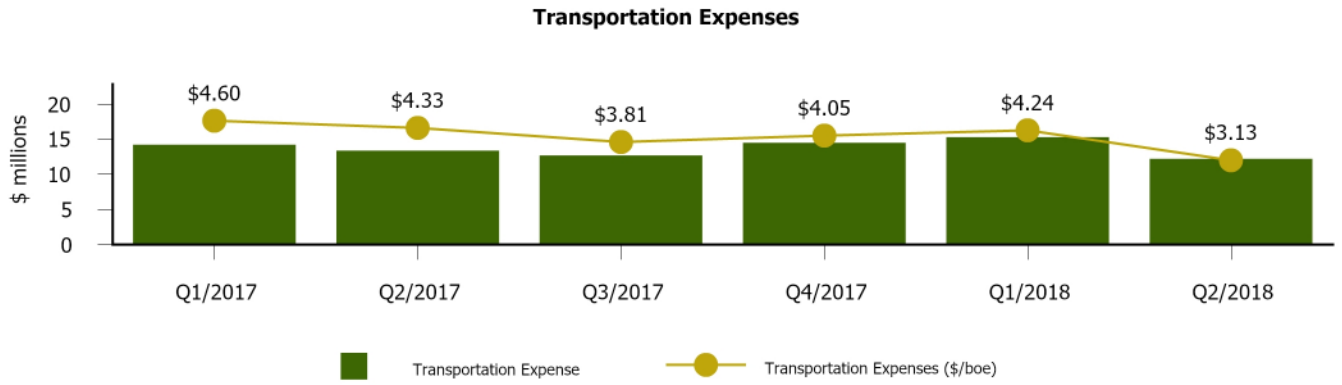
Colombian Transportation Expense

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Transportation expense ($000s)	**$ 12,200**	$ 13,449	**$ 27,543**	$ 27,629
Per unit ($/boe)	**3.13**	4.33	**3.66**	4.47

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

For the three months ended June 30, 2018, the cost of transportation on a per boe basis has decreased to $3.13/boe from the first quarter of 2018 of $4.24/boe and decreased from the comparative period in 2017 of $4.33/boe. This decrease is mainly a result of a change in the marketing mix of crude oil contracts where wellhead contracts incur no transportation costs and a corresponding reduced sale price (the increase price differential on a per boe basis was offset by a decrease in transportation costs per boe).

On a year to date basis transportation expense has decreased to $3.66/boe from $4.47/boe in the comparative period in 2017. The main reason for this decrease relates to an increase in wellhead oil sales contracts as explained above.



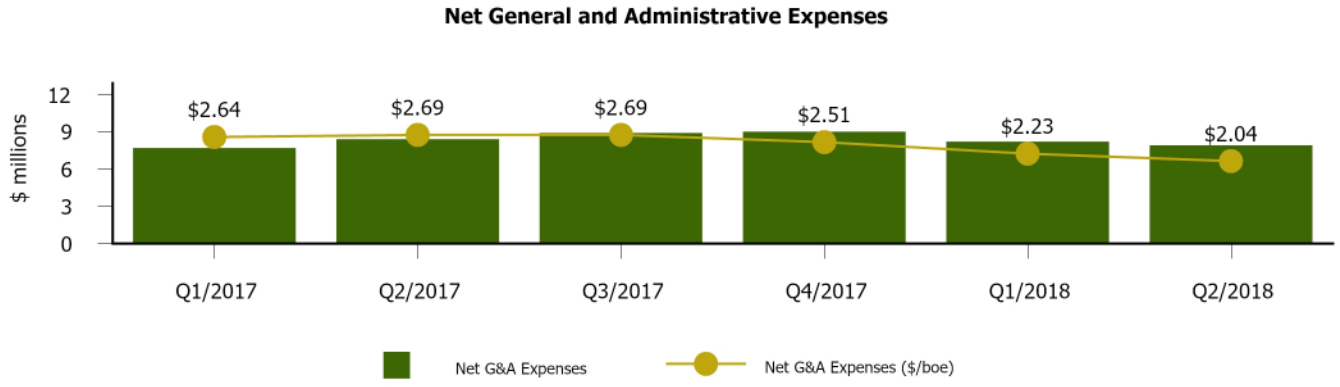
General and Administrative Expense ("G&A")

(000s)	For the three months ended June 30, 2018	2017	For the six months ended June 30, 2018	2017
Gross G&A	**$ 10,408**	$ 11,253	**$ 21,058**	$ 20,373
G&A recoveries	**(125)**	(160)	**(211)**	(289)
Capitalized G&A	**(2,353)**	(2,694)	**(4,762)**	(3,945)
Total net G&A	**$ 7,930**	$ 8,399	**$ 16,085**	$ 16,139
Per unit ($/boe) [1]	**2.04**	2.69	**2.14**	2.67

[1] Calculated based on Company working interest production volumes.

Net G&A was $7.9 million and $16.1 million for the three and six months ended June 30, 2018 compared to $8.4 million and $16.1 million for the same periods in 2017. Gross G&A was $10.4 million and $21.1 million for the three and six months ended June 30, 2018 (three and six months ended June 30, 2017 - $11.3 million and $20.4 million). On a per boe basis net G&A in the second quarter decreased 24 percent compared to the three months ended June 30, 2017. Net G&A on a per boe basis is expected to continue to decrease as the Company increases its operated capital expenditures over the next six months resulting in increased G&A capitalization.

The Company's G&A expense is denominated in local currencies of COP and Cdn dollar which if they were to appreciate/depreciate would have an impact on G&A expense. Refer below to the foreign exchange sensitivity analysis on page 14 for further information.



Share-Based Compensation

($000s)	For the three months ended June 30, 2018	2017	For the six months ended June 30, 2018	2017
Equity settled share-based compensation	**$ 3,496**	$ 5,045	**$ 7,009**	$ 9,771
Cash settled share-based compensation	**10,985**	(999)	**12,039**	855
Cash settled share-based compensation recoveries	**(593)**	(3)	**(876)**	(54)
Total net expense	**$ 13,888**	$ 4,043	**$ 18,172**	$ 10,572

Equity settled share-based compensation expense was $3.5 million for the three months ended June 30, 2018 compared to $5.0 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. The decrease from the prior year is mainly related to a decrease in the issuance of new options, RSUs, and PSUs, as applicable, under the plans in the current year as compared to the prior year.

Cash settled share-based compensation relates to the Company's cash settled incentive plans and includes share appreciation rights ("SARs"), cash settled restricted share units ("CRSUs") and deferred share units ("DSUs"). The CRSU plan is a new cash settled plan that will replace the current SAR plan as granted SAR's vest, and are excerised. There will be no SAR grants going foward. For the three months ended June 30, 2018 there was an expense of $10.4 million compared to $1.0 million recovery for the same period in 2017. Obligations for payments of cash under the

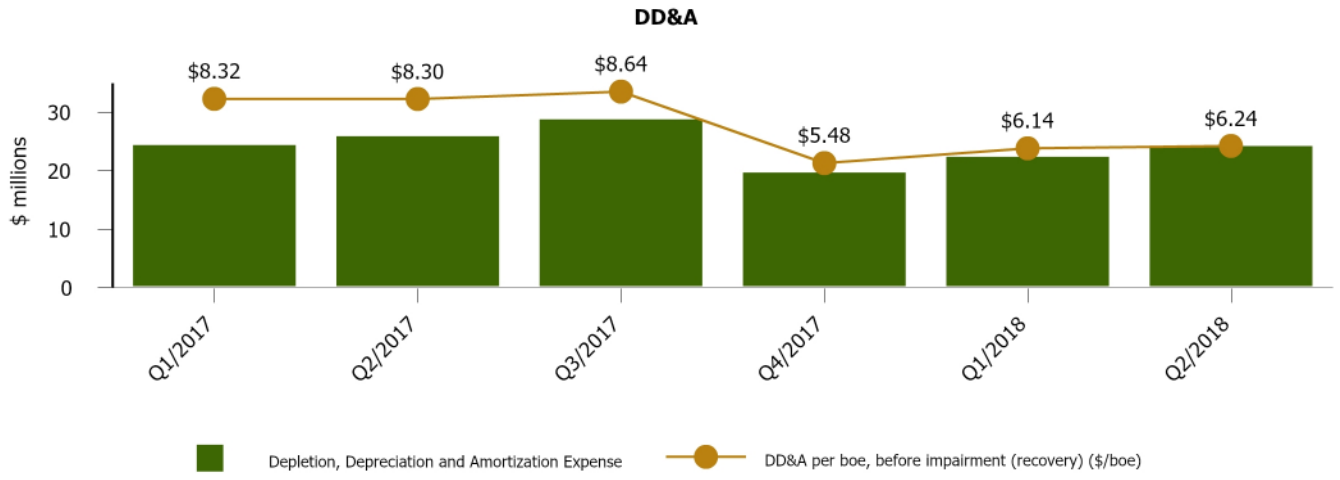
Company's cash settled incentive plans are accrued as an expense over the vesting period based on the fair value of the units as described in note 14 of the interim financial statements for the three and six months ended June 30, 2018. The expense in the current period is mainly due to a increase in the Company's share price from March 31, 2018 to June 30, 2018 and an increase in SARs and CRSUs expense paid. As at June 30, 2018, the total cash settled incentive plans liability accrued is $21.9 million (December 31, 2017 - $16.6 million).

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

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
DD&A expense (000s)	**$ 24,218**	$ 25,906	**$ 46,657**	$ 50,315
Per unit ($/boe)[1]	**6.24**	8.30	**6.19**	8.31

[1] DD&A per unit ($/boe) is calculated using Company working interest production volumes and does not include inventory adjustments.

Second quarter 2018 DD&A was $24.2 million ($6.24/boe) compared to $25.9 million ($8.30/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 CGU production mix from the prior comparative period.



Foreign Exchange (Gain) Loss

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Foreign exchange (gain) loss ($000s)	**$ (868)**	$ (2,527)	**$ 3,711**	$ (943)
Foreign Exchange Rates				
USD$/CAD$	**1.29**	1.34	**1.28**	1.33
USD$/Colombian peso	**2,840**	2,920	**2,849**	2,921

The Company's main exposure to foreign currency risk relates to the pricing of foreign currency denominated in Canadian dollars and Colombian pesos, as the Company's functional currency is the US dollar. The Company has exposure in Colombia and Canada on costs, such as capital expenditures, local wages, royalties and income taxes, all of which may be denominated in local currencies. The main drivers of foreign exchange (gains) losses are the revaluation of the Colombian peso denominated income tax, accounts payable and accounts receivable to USD at period end dates. During the three months ended June 30, 2018, the total foreign exchange gain was $0.9 million (three months ended June 30, 2017 – gain of $2.5 million). For the three months ended June 30, 2018, $0.1 million foreign exchange gain was realized and $0.8 million foreign exchange loss was unrealized (3 months ended June 30, 2017 - $3.4 million foreign exchange gain was realized and $0.8 million foreign exchange loss was unrealized). Unrealized foreign exchange gains and losses may be reversed in the future as a result of fluctuations in exchange rates and are recorded in the Company's consolidated statement of comprehensive income.

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

Foreign Exchange Sensitivity Analysis

		$/boe Impact of change in local currency/$USD exchange rate	
Cost component	Estimated percent of cost denominated in local currency	10% appreciation of local currency	10% depreciation of local currency
Production expense	80%	$ 0.46	$ (0.46)
Transportation expense	50%	$ 0.16	$ (0.16)
G&A expense	100%	$ 0.20	$ (0.20)

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 Q2 2018 per boe costs. This analysis ignores all other factors impacting cost structure including efficiencies, cost reduction strategies, etc.

Net Finance Expense (Income)

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Bank charges and credit facility fees	**$ 584**	$ 792	**$ 1,004**	$ 1,701
Accretion on decommissioning and environmental liabilities	**1,087**	1,174	**2,307**	2,009
Interest and other income	**(953)**	(492)	**(1,498)**	(876)
Unrealized loss on foreign currency risk management contracts	**1,282**	—	**1,282**	—
Loss on settlement of decommissioning liabilities	**2,981**	—	**2,981**	—
Colombian net wealth tax	**—**	—	**—**	894
Net finance expense	**$ 4,981**	$ 1,474	**$ 6,076**	$ 3,728

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Non-cash finance expense	**$ 5,350**	$ 1,174	**$ 6,570**	$ 2,009
Cash finance expense	**(369)**	300	**(494)**	1,719
Net finance expense	**$ 4,981**	$ 1,474	**$ 6,076**	$ 3,728

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 six months ended June 30, 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 on the commodity risk management contracts:

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Realized (gain) on commodity risk management contracts	**$ —**	$ (361)	**$ —**	$ (361)
Premiums paid on commodity risk management contracts	**364**	—	**544**	1,189
Unrealized (gain) loss on commodity risk management contracts	**26**	(730)	**242**	(3,237)
Total	**$ 390**	$ (1,091)	**$ 786**	$ (2,409)

The Company's unrealized derivative loss on risk management contracts for the three and six month periods ended June 30, 2018 was $0.03 million and $0.2 million (three and six month periods ended June 30, 2017 – gain of $0.7 million and $3.2 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 includes premiums paid for the six month period ended June 30, 2018 of $0.5 million (six month period ended June 30, 2017 - $1.9 million). The premiums allowed Parex to enter into contracts that had higher purchase put and higher ceiling call options prices than without the premiums.

b) Risk Management Contracts – Foreign Exchange

The Company is exposed to foreign currency risk as various portions of its cash balances are held in Canadian dollars (Cdn$) and Colombian pesos (COP$) while its committed capital expenditures are expected to be primarily denominated in US dollars.

The following is a summary of the foreign currency risk management contracts in place as at June 30, 2018:

Period Hedged	Reference	Currency Option Type	Amount USD	Strike Price
April 25, 2018 to April 25, 2019	Colombian Peso	Costless Collar	$20,000,000	2,700-3,025
June 28, 2018 to April 25, 2019	Colombian Peso	Costless Collar	$60,000,000	2,750-3,160

The table below summarizes the loss on the foreign currency risk management contracts:

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Unrealized loss on foreign currency risk management contracts	**$ 1,282**	$ —	**$ 1,282**	$ —
Total	**$ 1,282**	$ —	**$ 1,282**	$ —

The fair value of the foreign currency risk management contracts is recorded in the financial statement line item "Derivative financial instruments" in the consolidated balance sheet.

The Company recorded a $1.3 million loss on these contracts in the three months ended June 30, 2018 which is recorded in the financial statement line item "Finance expense" in the consolidated statements of comprehensive income.

Subsequent to June 30, 2018, the Company entered into the following foreign currency risk management contract:

Period Hedged	Reference	Currency Option Type	Amount USD	Strike Price
July 24, 2018 to July 25, 2019	Colombian Peso	Costless Collar	$60,000,000	2,750-3,100

Income Tax

The components of tax expense for the three and six months ended June 30, 2018 and 2017 were as follows:

	For the three months ended June 30,		For the six months ended June 30,	
	2018	2017	**2018**	2017
Current tax expense	**$ 173,122**	$ 7,505	**$ 200,402**	$ 12,362
Deferred tax (recovery) expense	**(239,234)**	19,617	**(238,684)**	18,340
Tax expense (recovery)	**$ (66,112)**	$ 27,122	**$ (38,282)**	$ 30,702

The current and deferred tax (recovery) expense relates to the Company's operations in Colombia. Current tax in the three months ended June 30, 2018 was $173.1 million expense as compared to $7.5 million expense in the three months ended June 30, 2017. The increase in the current tax expense from the comparative period is a result of the voluntary tax restructuring completed in the three months ended June 30, 2018. Approximately $137.5 million relates to the voluntary tax restructuring while approximately $35.6 million relates to tax on Colombian cash flows in the three months ended June 30, 2018 as a result of the increase in oil prices driving higher taxable income.

Deferred tax in the three months ended June 30, 2018 was a recovery of $239.2 million ($19.6 million expense for the three months ended June 30, 2017). The main driver of the recovery of deferred tax was the voluntary tax restructuring completed in the quarter as a result of the increase in tax basis of the Company's key assets.

Assuming current Brent strip pricing and existing Colombian tax regulations, the tax restructuring expected benefits are as follows:

- Increased tax basis on key assets by approximately $765 million to $1.1 billion;
- Reduced forecast Q3 2018 to Q4 2018 effective tax rate on operating cash flow to 15%-17% from 23-25%;
- Reduced forecast long-term effective tax rate on operating cash flow to 16%-19% from approximately 20%-25%;

The calculation of current and deferred income tax in Colombia is based on a number of variables which can cause swings in current and deferred income tax. These variables include but are not limited to the year end producing reserves used in calculating depletion for tax purposes, the timing and number of dry hole write-offs permissible for Colombian tax purposes and currency fluctuations.

At current benchmark crude oil prices and the Company's current capital expenditure forecast, the Company expects total 2018 current tax expense to be between $245-255 million.

Capital Expenditures

For the three months ended June 30,	Colombia		Canada		Total	
($000s)	**2018**	2017	**2018**	2017	**2018**	2017
Acquisition of unproved properties	**$ 82**	$ 1,971	**$ —**	$ —	**$ 82**	$ 1,971
Geological and geophysical	**5,149**	—	**—**	—	**5,149**	—
Drilling and completion	**92,441**	46,661	**—**	—	**92,441**	46,661
Well equipment and facilities	**2,818**	10,240	**—**	—	**2,818**	10,240
Other	**—**	136	**77**	—	**77**	136
Total capital expenditures	**$ 100,490**	$ 59,008	**$ 77**	$ —	**$ 100,567**	$ 59,008

For the six months ended June 30, ($000s)	Colombia 2018	Colombia 2017	Canada 2018	Canada 2017	Total 2018	Total 2017
Acquisition of unproved properties	**$ 67**	$ 2,096	**$ —**	$ —	**$ 67**	$ 2,096
Geological and geophysical	**7,022**	(69)	**—**	—	**7,022**	(69)
Drilling and completion	**140,435**	78,939	**—**	—	**140,435**	78,939
Well equipment and facilities	**11,174**	13,445	**—**	—	**11,174**	13,445
Other	**—**	136	**79**	24	**79**	160
Total capital expenditures	**$ 158,698**	$ 94,547	**$ 79**	$ 24	**$ 158,777**	$ 94,571

Capital Expenditures Summary

During the six months ended June 30, 2018 the Company incurred $158.8 million of capital expenditures compared to $94.6 million in the same period of 2017. During Q2, 2018 the Company drilled 18 gross (11.35 net) wells, compared to 12 gross (7.30 net) wells in the comparative period. During Q2, 2018, total drilling and completion costs were $92.4 million of which the majority related to drilling, completion and capitalized workover costs at Block LLA-34, Cabrestero Block, Capachos and VIM-1.

During the six months ended June 30, 2018 capital expenditures of $158.8 million were self funded from funds flow from operations of $222.6 million adjusted for the one time voluntary tax restructuring of $137.5 million that occurred in the three months ended June 30, 2018. The Company strives to fund its annual capital expenditures from funds flow and has demonstrated this goal since 2012 however on a quarterly basis funds flow may be greater or less than capital expenditures due to timing of capital programs and other variables.

Summary of Quarterly Results

Three months ended ($000s)	**June 30, 2018**	March 31, 2018	Dec. 31, 2017	Sep. 30, 2017
Average daily oil and natural gas production (boe/d)	**42,625**	40,586	39,007	36,195
Average realized sales price – oil and natural gas ($/boe)	**61.96**	55.98	50.43	41.16
Financial (000s except per share amounts)				
Oil sales	**$ 241,765**	$ 202,450	180,738	136,956
Funds flow (used in) provided by operations[3]	**$ (15,768)**	$ 100,901	$ 93,861	$ 65,998
Per share – basic	**(0.10)**	0.65	0.61	0.43
Per share – diluted[1]	**(0.10)**	0.64	0.59	0.42
Net income	**$ 188,601**	$ 71,512	$ 55,921	$ 55,527
Per share – basic	**1.21**	0.46	0.36	0.36
Per share – diluted	**1.18**	0.45	0.36	0.35
Capital Expenditures, excluding corporate acquisitions	**$ 100,567**	$ 58,210	$ 66,341	$ 51,434
Total assets (end of period)	**$ 1,586,249**	$ 1,229,897	$ 1,121,908	$ 1,057,859
Working capital surplus (end of period) [2]	**$ 66,050**	$ 205,771	$ 163,401	$ 140,292

[1]Non-GAAP term. See "Non-GAAP Terms" below.
[2]Working capital does not include the undrawn amount available on the credit facility.
[3]For the three months ended June 30, 2018, funds flow provided by operations includes a $137.5 million ($0.88 per share basic) charge for a voluntary tax restructuring, refer to the "Income Tax" section.

Three months ended ($000s)	June 30, 2017	March 31, 2017	Dec. 31, 2016	Sep. 30, 2016
Average daily oil and natural gas production (boe/d)	34,291	32,591	31,049	29,754
Average realized sales price - oil ($/boe)	40.26	42.21	36.96	35.73
Financial (000s except per share amounts)				
Oil and gas sales	124,995	130,079	112,201	113,367
Funds flow provided by operations[3]	$ 51,763	$ 67,906	$ 51,791	$ 45,091
Per share – basic	0.34	0.44	0.34	0.30
Per share – diluted[1]	0.33	0.43	0.33	0.29
Net income (loss)	$ 3,524	$ 40,106	$ (45,439)	$ 6,811
Per share – basic	0.02	0.26	(0.30)	0.04
Per share – diluted	0.02	0.26	(0.30)	0.04
Capital Expenditures, excluding corporate acquisitions	$ 59,008	$ 35,563	$ 66,890	$ 26,313
Total assets (end of period)	$ 1,015,540	$ 984,855	$ 918,671	$ 947,354
Working capital surplus (end of period) [2]	$ 128,347	$ 131,056	$ 93,290	$ 117,747

[1]Non-GAAP term. See "Non-GAAP Terms" below.
[2]Working capital does not include the undrawn amount available on the credit facility.
[3]For the three months ended June 30, 2017, funds flow provided by operations includes a $15.0 million ($0.09 per share basic) charge for a one time legal settlement.

Factors that Caused Variations Quarter Over Quarter

During the second quarter of 2018, production of 42,625 boe/d was in excess of production for the previous quarter ended March 31, 2018. Revenue was higher than the previous quarter mainly due to a increase in world oil prices and an increase in production in the period. Funds flow from operations was negative $15.8 million which is significantly lower than the previous quarter due to a voluntary tax restructuring that had a $137.5 million impact. Adjusting for this one-time payment, funds flow increased to $121.7 million, which is higher than the previous 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 from operations 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 from 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.

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 June 30, 2018 the Company had a working capital surplus of $66.1 million, excluding funds available under the credit facility, as compared to working capital surplus at December 31, 2017 of $163.4 million. Bank debt was $nil as at June 30, 2018, December 31, 2017 and June 30, 2017. The credit facility has a current borrowing base of $100.0 million (December 31, 2017 - $100.0 million) and is subject to a borrowing base redetermination to be completed by the end of October 2018. At June 30, 2018 Parex held $323.1 million of cash, compared to $235.0 million at December 31, 2017 and $202.9 million at June 30, 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 decrease in the Company's working capital position from December 31, 2017 is due to the $137.5 million voluntary tax restructuring cost partially offset by the Company generating cash flow in excess of capital expenditures for the six months ended June 30, 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 June 30, 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. The Company currently has $nil bank debt and no plans in 2018 to utilize the credit facility.

Refer to note 21 - Commitments of the interim financial statements for the period ended June 30, 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 June 30, 2018 the Company had 155,579,476 common shares outstanding.

The Company has a stock option plan 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 August 8, 2018 Parex has the following securities outstanding:

	Number	%
Common shares	155,434,628	95 %
Stock options	4,364,414	3 %
Restricted and performance share units	2,940,595	2 %
	162,739,637	**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 June 30, 2018 were $127.8 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 $101.3 million (December 31, 2017 - $116.1 million) of the letters of credit issued on behalf of Parex at June 30, 2018. Also at June 30, 2018, there is an additional $26.5 million (December 31, 2017 - $26.4 million) of letters of credit that are provided by a Latin American bank on an unsecured basis. The letters of credit issued to the ANH and Ecopetrol are reduced from time to time to reflect the work performed on the various blocks.

The following table summarizes the Company's estimated undiscounted commitments as at June 30, 2018:

(000s)		Total	<1 year	1 – 3 years	3 – 5 years	>5 years
Exploration	$	147,227	136,772	10,455	—	—
Office and accommodations[1]		12,123	2,407	4,088	3,294	2,334
Decommissioning and Environmental Obligations		95,844	10,145	—	—	85,699
Total	**$**	**255,194**	**149,324**	**14,543**	**3,294**	**88,033**

(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 (gain) loss		528		(412)		116
Balance, December 31, 2017		36,774		15,906		52,680
Additions		3,542		993		4,535
Additions related to change in estimate		(178)		(118)		(296)
Settlements of obligations during the period		(3,843)		(84)		(3,927)
Loss on settlement of obligations		2,981		—		2,981
Accretion expense		1,287		1,020		2,307
Foreign exchange loss		478		30		508
Balance, June 30, 2018	**$**	**41,041**	**$**	**17,747**	**$**	**58,788**
Current obligation		(3,555)		(6,590)		(10,145)
Long-term obligation	**$**	**37,486**	**$**	**11,157**	**$**	**48,643**

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 June 30, 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 $73.5 million as at June 30, 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 $3.6 million (December 31, 2017 –$4.2 million) that is classified as a current obligation. During the six months ended June 30, 2018 the loss on settlement of obligations of $3.0 million primarily related to higher than expected abandonment costs on the El Eden block.

The total undiscounted amount of cash flows required to settle the Company's environmental liability is approximately $22.3 million as at June 30, 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 $6.6 million (December 31, 2017 –$5.6 million) that is classified as a current obligation.

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

- Changes in laws and legislation;
- Construction of new facilities;
- Change in commodity price;
- Change in the estimate of oil reserves and the resulting amendment to the life of reserves;
- Changes in technology; and
- Execution of decommissioning liabilities, specifically cost of the actual work to abandon and reclaim.

Subsequent Event

On July 17, 2018 the Company announced that its Board of Directors have determined it is timely, prudent and in the best interests of the Company to initiate a formal process to explore, review and evaluate strategic repositioning alternatives with a view to enhancing shareholder value.

The strategic repositioning review will focus on the potential sale of the Company's Southern Casanare ("SoCa") assets (LLA-32, LLA-34 and Cabrestero), the retention of its exploration assets and the return of the net sale proceeds to shareholders. Consideration will also be given to a corporate sale or other strategic actions that would result in the creation of additional value for shareholders. This review of strategic repositioning alternatives may result in no specific transaction being pursued, with the Company continuing its operations as they currently exist with a focus on sustainable self-funded growth.

Parex has not set a definitive schedule to complete its identification, examination and consideration of strategic repositioning alternatives or made a decision to pursue any particular strategic repositioning alternative. The review process was not initiated as a result of receiving any transaction proposal. Given the nature of the process and the need for confidentiality during the process, the Company does not intend to provide updates until such time as the Board of Directors approves a definitive transaction or strategic repositioning alternative, or otherwise determines that further disclosure is necessary or appropriate. The Company cautions that there are no guarantees that the review of strategic repositioning alternatives will result in a transaction, or, if a transaction is undertaken, as to its terms, timing or conditions or approvals required to implement such transaction.

As a result of the strategic repositioning alternatives review process, Parex terminated its automatic share purchase plan to purchase up to 3,000,000 of its common shares pursuant to the Company's normal course issuer bid.

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 $320 - $330 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 expected capital expenditures 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;
- the Company's anticipated annual production for 2018 including the percentage of such production that is oil;

- effect of change to the mix of crude marketing contract types on realized price differential and transportation expense;
- expected timing of the draw down of crude oil inventories in transit;
- the Company's expectations regarding future decrease to net G&A on a per boe basis;
- the Company's expectations regarding the per boe and G&A expense 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 expected effect of changes in commodity and foreign exchange forward strip prices on the fair value of financial contracts;
- the Company's estimated effective current tax rate for 2018;
- the Company's estimated current tax expense for 2018;
- the Company's forecast tax restructuring benefits;
- 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 it's credit facility will not impact its current or future operations or reduce the 2018 outlook;
- estimated amounts, timing and the anticipated sources of funding for the Company's exploration, office and accommodations, environmental, decommissioning and restoration obligations.
- the statements set forth under "Accounting Policies and Estimates" in this MD&A;
- the potential outcome of the Company's review of strategic repositioning alternatives;
- the anticipated focus of the Company's review of strategic repositioning alternatives; and
- the Company's plans regarding providing updates on the status of the Company's review of strategic repositioning alternatives.

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; risk of failure to achieve preceived benefits from voluntary tax restructuring; failure of counterparties to perform under the terms of their contracts; changes to pipeline capacity; risk that Parex' evaluation of its existing portfolio of development and exploration opportunities is not consistent with its expectations; failure to meet expected production targets; risk that the review of strategic repositioning alternatives will not result in a transaction; 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; timing and number of dry hole write-offs permitted for Colombian tax purposes; anticipated benefits from voluntary tax restructuring; 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; on-stream timing of production from successful exploration wells; operational performance of non-operated producing fields; pipeline capacity; the benefits of initiating a review of strategic repositioning alternatives; 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 or generate sufficient cash flow to develop such reserves.

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

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

This MD&A may contain future oriented financial information ("FOFI") within the meaning of applicable securities laws. The FOFI has been prepared by management to provide an outlook of the Company's activities and results and may not be appropriate for other purposes. The FOFI has been prepared based on a number of assumptions including the assumptions discussed above. The actual results of operations of the Company and the resulting financial results may vary from the amounts set forth herein, and such variations may be material. The Company and management believe that the FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments. FOFI contained in this MD&A was made as of the date of this MD&A and the Company disclaims any intention or obligations to update or revise any FOFI contained in this MD&A, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law.

Non-GAAP Terms

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

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

	For the three months ended June 30,		For the six months ended June 30,	
(000s)	**2018**	2017	**2018**	2017
Funds flow (used in) provided by operations	**$ (15,765)**	$ 51,763	**$ 85,136**	$ 119,669
Weighted average number of shares for the purposes of basic funds flow	**155,771**	154,249	**155,406**	153,769
Dilutive effect of share options on potential common shares	**4,553**	3,814	**4,152**	3,564
Weighted average number of shares for the purposes of diluted funds flow	**160,324**	158,063	**159,558**	157,333

Adjusted funds flow from operations *is funds flow provided by operations adjusted to exclude a* $137.5 million *one time voluntary tax restructuring during the three months ended June 30, 2018 and a $15.0 million one time legal settlement during the three months ended June 30, 2017.*

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

	For the three months ended June 30,		For the six months ended June 30,	
($000s)	**2018**	2017	**2018**	2017
Oil and natural gas revenue excluding risk management contracts	**$ 241,765**	$ 124,995	**$ 444,215**	$ 255,074
Denominator (BOEs)				
Company produced oil and natural gas sales in period	**3,849,937**	3,079,531	**7,441,272**	6,102,958
Purchased oil volumes sold	**51,961**	25,025	**77,649**	84,165
Total oil and natural gas sales volumes	**3,901,898**	3,104,556	**7,518,921**	6,187,123
Sales price per boe	**$ 61.96**	$ 40.26	**$ 59.08**	$ 41.23

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 June 30,		For the six months ended June 30,	
($000s)	**2018**	2017	**2018**	2017
Royalty expense	**$ 31,177**	$ 12,421	**$ 57,356**	$ 25,673
Denominator (BOEs)				
Company produced oil and natural gas sales in period	**3,849,937**	3,079,531	**7,441,272**	6,102,958
Royalty expense per boe	**$ 8.10**	$ 4.03	**$ 7.71**	$ 4.21

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 June 30,		For the six months ended June 30,	
($000s)	**2018**	2017	**2018**	2017
Production Expense	**$ 22,193**	$ 16,363	**$ 41,395**	$ 31,752
Denominator (BOEs)				
Company produced oil and natural gas sales in period	**3,849,937**	3,079,531	**7,441,272**	6,102,958
Production expense per boe	**$ 5.76**	$ 5.31	**$ 5.56**	$ 5.20

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

($000s)	For the three months ended June 30, **2018**	2017	For the six months ended June 30, **2018**	2017
Transportation Expense	**$ 12,200**	$ 13,449	**$ 27,543**	$ 27,629
Denominator (BOEs)				
Company produced oil and natural gas sales in period	**3,849,937**	3,079,531	**7,441,272**	6,102,958
Purchased oil volumes sold	**51,961**	25,025	**77,649**	84,165
Total oil and natural gas sales volumes	**3,901,898**	3,104,556	**7,518,921**	6,187,123
Transportation expense per boe	**$ 3.13**	$ 4.33	**$ 3.66**	$ 4.47

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

($000s)	For the three months ended June 30, **2018**	2017	For the six months ended June 30, **2018**	2017
Funds flow (used in) provided by operations	**$ (15,765)**	$ 51,763	**$ 85,136**	$ 119,669
Capital expenditures, excluding corporate acquisitions	**100,567**	59,008	**158,777**	94,571
Free funds flow (deficiency)	**$ (116,332)**	$ (7,245)	**$ (73,641)**	$ 25,098

Impact of Accounting Policy Change

On January 1, 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 six ended June 30, 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 six months ended June 30, 2018.

Financial Instruments and Other Instruments

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

Accounting Policies and Estimates

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 $20.4 million reduction to revenue in the three months ended June 30, 2017 with a corresponding reduction of $20.4 million to transportation expense. The effect of the reclassification on the prior period is presented below:

For the three months ended (000s)		**June 30, 2017**
Decrease in sales of crude oil	$	(20,411)
Decrease in transportation expense		(20,411)
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:

	Measurement Category [1]	
Financial Instrument	**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 June 30, 2018, all 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 0.3 percent at June 30, 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
mbbls	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
mbbls/d	one thousand barrels per day
BOE or boe	barrel of oil equivalent, using the conversion factor of 6 Mcf: 1 bbl
mboe	one thousand barrels of oil equivalent
mmboe	one million barrels of oil equivalent
bfpd	barrels of fluid per day
boe/d	barrels of oil equivalent per day
mcf	thousand cubic feet
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 equivalen conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.