PACIFIC E&P

MANAGEMENT
DISCUSSION & ANALYSIS

November 14, 2016
For the three months ended September 30, 2016

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Legal Notice – Forward-Looking Information and Statements

Certain statements in this Management, Discussion, and Analysis ("**MD&A**") constitute forward-looking statements. Often, but not always, forward-looking statements use words or phrases such as "expects," "does not expect," "is expected," "anticipates," "does not anticipate," "plans," "planned," "estimates," "estimated," "projects," "projected," "forecasts," "forecasted," "believes," "intends," "likely," "possible," "probable," "scheduled," "positioned," "goal," or "objective." In addition, forward-looking statements often state that certain actions, events, or results "may," "could," "would," "might," or "will" be taken, occur, or be achieved. Such forward-looking statements, including, but not limited to, statements with respect to anticipated levels of production, estimated costs, and timing of the Company's planned work programs and reserves determination, involve known and unknown risks, uncertainties, and other factors that may cause the actual levels of production, costs, and results to be materially different from the estimated levels expressed or implied by such forward-looking statements. The Company believes the expectations reflected in these forward-looking statements are reasonable, but the Company cannot assure that such expectations will prove to be correct, and thus, such statements should not be unduly relied upon. Factors that could cause actual results to differ materially from those anticipated in these forward-looking statements are described under the heading "Risks and Uncertainties." Although the Company has attempted to take into account important factors that could cause actual costs or operating results to differ materially, there may be other unforeseen factors that increase costs for the Company, and so results may not be as anticipated, estimated, or intended.

Statements concerning oil and gas reserve estimates may also be deemed to constitute forward-looking statements to the extent that they involve oil and gas that will be encountered only if the property in question is developed. The estimated values disclosed in this MD&A do not represent fair-market value. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates for all properties due to the effects of aggregation. Disclosure of well test results may be preliminary until analyzed or interpreted and are not necessarily indicative of long-term performance or ultimate recovery.

For more information, please see the Company's Amended and Restated Annual Information Form, dated October 17, 2016 (the "**Annual Information Form**"), available at www.sedar.com.

This MD&A is management's assessment and analysis of the results and financial condition of the Company and should be read in conjunction with the accompanying Interim Condensed Consolidated Financial Statements and related notes for the three months ended September 30, 2016 and 2015. The preparation of financial information is reported in United States dollars and is in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board ("**IASB**") unless otherwise noted. All comparative percentages are between the quarters ended September 30, 2016 and 2015, unless otherwise noted.

In order to provide shareholders with full disclosure relating to potential future capital expenditures, the Company has provided cost estimates for projects that in some cases are still in the early stages of development. These costs are preliminary estimates only. The actual amounts are expected to differ, and these differences may be material. For further discussion of the significant capital expenditures, see "Capital Expenditures" on page 16.

Additional information with respect to the Company, including the Company's quarterly and annual financial statements and the Annual Information Form, has been filed with Canadian securities regulatory authorities and is available on SEDAR at www.sedar.com and on the Company's website at www.pacific.energy. Information contained in or otherwise accessible through our website does not form a part of this MD&A and is not incorporated by reference into this MD&A.

1 Restructuring Transaction

Restructuring Successfully Completed

Since late 2014, the Company has grappled with the impact of low oil prices on its operations and debt burden and ultimately entered into the Restructuring Transaction (defined below). However, Pacific has now emerged from its recapitalization with a renewed strategic focus, positive cash flow, strong balance sheet, significantly reduced payables, and a Board of Directors with the skills and experience needed to guide management and drive value creation for all stakeholders.

The Restructuring Transaction will allow Pacific to implement a strategy to narrow its geographic focus and reduce organizational scale, complexity and cost while maximizing operating and cost efficiencies to ensure the Company has sustainable production and growth. As part of this strategy, the Company expects to be reviewing the broad set of upstream and midstream assets within the Company's portfolio with an emphasis on value-maximizing initiatives.

The Company also effected significant changes to its corporate governance by appointing a new Board comprised of seven directors with the necessary industry and financial experience to guide Pacific towards reaching its full potential. Members are Gabriel de Alba, Luis F. Alarcon, W. Ellis Armstrong, Raymond Bromark, Russell Ford, Barry Larson, and Camilo Marulanda. Gabriel de Alba, Managing Director and Partner at The Catalyst Capital Group Inc. ("**Catalyst**"), has been appointed Chairman of the Board of Directors.

The Company also announced that Ronald Pantin and Carlos Perez will retire from their positions as CEO and CFO of Pacific, respectively, by November 30, 2016, at which time, Camilo McAllister, a seasoned Colombian oil and gas executive, will become Pacific's CFO. Jim Latimer, previously the Chief Restructuring Officer at Pacific, was also appointed interim President and CEO while the Board, assisted by executive search firm Spencer Stuart, completes the process to select a permanent replacement. The appointments of Messrs. McAllister and Latimer are subject to regulatory approval.

Background on, and Effect of, Restructuring

On April 19, 2016, recognizing that the Company had to undergo a full corporate debt-restructuring to best preserve the assets of the Company, the then Board of Directors, acting on a recommendation from its specially-formed committee of independent directors, approved a comprehensive restructuring transaction (the "**Restructuring Transaction**") with: (i) Catalyst, on behalf of investment funds managed by it; (ii) certain holders of the Company's senior unsecured notes (including certain members of an ad hoc committee comprised of holders of the Company's senior unsecured notes); and (iii) certain of the Company's lenders under its credit facilities. Under the terms of the restructuring, the claims of the Company's senior noteholders, its lenders under the credit facilities, and certain other third parties (collectively, the "**Affected Creditors**") would be exchanged for new common shares of the reorganized company. In addition, Catalyst and certain Affected Creditors would provide new cash financing to recapitalize the Company.

On April 27, 2016, the Company announced that it and certain of its direct and indirect subsidiaries (collectively, the "**Filing Entities**") obtained an initial order (the "**Initial Order**") from the Superior Court of Justice in Ontario (Commercial List) (the "**Court**") under the Companies' Creditors Arrangement Act (Canada) ("**CCAA**"). This authorized the Filing Entities to commence the court-supervised Restructuring Transaction.

Further, on May 3, 2016, the Company and the Colombian branches of its subsidiaries Meta Petroleum Corp., Pacific Stratus Energy Colombia Corp., and Petrominerales Colombia Corp. filed a request for recognition in Colombia under Law 1116 of: (i) the application for protection, filed on April 27, 2016, under the CCAA with the Court in Ontario; and (ii) the Initial Order.

On June 9, 2016, the United States Bankruptcy Court for the Southern District of New York entered an order under chapter 15 of title 11 of the United States Code granting recognition of the CCAA proceedings.

On August 17, 2016, a resolution approving the plan of compromise and arrangement proposed by the Company to implement the Restructuring Transaction (the "**Plan**") was approved by 98.4% of the Company's creditors eligible to vote, which included its noteholders, lenders under its respective credit facilities, and all other creditors for which the Company commenced a claims process. Subsequently, on August 23, 2016, the Court approved the Plan.

The Restructuring Transaction was subject to certain conditions, including creditor and court approval, and was completed on November 2, 2016. The Restructuring Transaction included the following key features:

- Implementation of the Plan pursuant to a court-supervised CCAA process in Canada, together with appropriate proceedings in Colombia under Law 1116, and in the United States under chapter 15 of title 11 of the United States Code.
- Certain of the Company's Affected Creditors (the "**Funding Creditors**") and Catalyst jointly provided $500 million of debtor-in-possession financing (the "**DIP Financing**") less an original issue discount of 4%. The DIP Financing was secured by a superpriority lien over the assets of the Company and its subsidiaries (the "**Pacific Group**") including pledges or other security over shares of the Pacific Group, inventory, bank accounts, accounts receivable, and economic rights under exploration and production contracts. Catalyst provided $240 million for the purchase of notes (after taking into account the original issue discount) pursuant to the DIP Financing (the "**Plan Sponsor DIP Financing**") and the Funding Creditors provided $240 million for the purchase of notes (after taking into account the original issue discount) (the "**Creditor DIP Financing**").
- As part of the Creditor DIP Financing, the Company issued to the Funding Creditors warrants (the "**Warrants**"), with a nominal exercise price, exercisable for up to 12.5% of the fully diluted common shares of the reorganized Company on implementation of the Restructuring Transaction.
- The claims by the Affected Creditors regarding approximately $4.1 billion of senior unsecured notes, approximately $1.2 billion of obligations under the Company's credit facilities, as well as the claims of certain other unsecured creditors of the Company (but not of the Company's subsidiaries), were settled in exchange for approximately 56.3% of the fully diluted common shares of the reorganized Company, which was paid pro rata, other than 2.2% of the common shares of the reorganized Company, allocated from amounts otherwise payable to holders of senior unsecured notes (the "**Affected Creditor Consideration**"). The Affected Creditor Consideration was paid to the holders of the senior unsecured notes who, among other things, signed a support agreement, or a joinder thereto, prior to May 6, 2016.
- The Affected Creditors also had the opportunity to receive cash in lieu of some or all of the common shares of the reorganized Company that they would otherwise be entitled to receive, subject to the terms and limits of a cash election made available under the Restructuring Transaction (the "**Cash Elections**"). Approximately 1.85% of the common shares of the reorganized company were acquired by Catalyst as Plan Sponsor and certain of the Company's Affected Creditors (collectively, the "**Equity Subscribers**") through subscriptions to fund the Cash Elections, at a minimum price of $16.00 and at an average cost of $17.63 per share.
- On implementation of the Restructuring Transaction, the Plan Sponsor DIP Financing was exchanged for 29.3% of the newly issued common shares of the Company. Cataylst acquired an additional 1.5% of the common shares through subscriptions to fund the Cash Elections, for a total interest of approximately 30.8% of the fully diluted common shares of the reorganized Company.
- The Creditor DIP Financing was not repaid upon the Company's exit under the Restructuring Transaction, but instead was amended and restated as five-year secured notes (the "**Exit Notes**"). The Exit Notes accrue interest at a rate equal to 10% per annum and may be redeemed by the Company subject to certain terms, including the payment of a prepayment premium. For a period of two years following the date the Restructuring Transaction is implemented, the Company will have the option, if the Company's unrestricted cash in operating accounts falls below $150 million, to make "payments-in-kind" with respect to any interest payment owed on the Exit Notes at a rate of 14% per annum.On implementation of the Restructuring Transaction, the Funding Creditors exercised the Warrants and were issued 12.5% of the fully diluted common shares of the Company.

- The common shares of the Company were consolidated on the basis of one post-consolidated share for each 100,000 common shares outstanding immediately prior to the consolidation, and any fractional common shares were rounded down to the nearest whole number without consideration in respect thereof.
- On completion of the Restructuring Transaction, there were 50,002,537 fully diluted common shares in the reorganized Company, allocated as follows:

Shareholder	Percentage
Catalyst (1)	30.8%
Affected Creditors (1)	69.2%

(1) Includes shares Catalyst and certain Affected Creditors received through subscriptions to fund the Cash Elections.

- The Company's common shares that were issued and outstanding prior to the implementation of the Restructuring Transaction were extensively diluted as a result of the 100,000 to one consolidation.

The Restructuring Transaction substantially improved the capital structure of the Company by reducing the amount of outstanding debt by approximately $5.1 billion, from $5.3 billion as of September 30, 2016, to $250 million (after giving effect to the Restructuring Transaction on a *pro forma* basis), which represents the total aggregate amount outstanding under the Exit Notes. Cash at September 30, 2016 was $556 million and upon emergence was approximately $556 million.

The Company's operations have been cash flow positive during the restructuring, with a focus on substantially reducing payables, which were reduced significantly to $764 million at September 30, 2016 from the $1.217 billion balance at December 31, 2015. Cash was also used to pay for capital expenditures ($97 million as of September 30, 2016), one-time restructuring costs (estimated to be $112.3 million at emergence), interest on the DIP notes and DIP LC Facility ($16.3 million as of September 30, 2016 and $5.3 million at emergence), and the establishment of restricted cash accounts in order to ensure the payment of Colombian creditors ($50 million as of September 30, 2016 and $39 million at emergence).

The Restructuring Transaction provided $480 million of additional liquidity through the DIP Financing and a committed letter of credit facility of approximately $116 million. With an improved capital structure, the Company will benefit from a reduction in its annual interest cost of approximately $232 million and no material debt maturing until 2021.

Pursuant to the Restructuring Transaction, the Company's common shares were approved for listing on the Toronto Stock Exchange under the symbol "PEN" and trading began on November 3, 2016.

The following table sets out the pro forma balance sheet as of September 30, 2016, giving effect to the Restructuring Transaction:

(in thousands of US$)	As reported September 30, 2016	Effect of the Restructuring transaction	Pro forma September 30, 2016
Cash and cash equivalents	$ 555,724	$ -	$ 555,724
Current assets other than cash	375,367	-	375,367
Non-current assets	1,472,511	-	1,472,511
Total assets	$ 2,403,602	$ -	$ 2,403,602
Current liabilities (1)	$ 797,169	$ (183,227)	$ 613,942
Loans and borrowings (1)	5,814,681	(5,564,681)	250,000
Non-current liabilities	310,186	-	310,186
Total liabilities	$ 6,922,036	$ (5,747,908)	$ 1,174,128
Common shares (2)	$ 2,615,788	$ 881,435	$ 3,497,223
Contributed surplus	124,150	-	124,150
Other reserves	(229,633)	-	(229,633)
Retained deficit	(7,163,424)	4,866,473	(2,296,951)
Deficit attributable to equity holders of the parent	(4,653,119)	5,747,908	1,094,789
Non-controlling interests	134,685	-	134,685
Shareholders' equity	$ (4,518,434)	$ 5,747,908	$ 1,229,474
Total Shareholders' equity and liabilities	$ 2,403,602	$ -	$ 2,403,602

(1) The pro forma effects on Current Liabilities and Loans and Borrowings include the exchange of the senior unsecured notes, the credit facilities, and Catalyst's DIP Note for common shares, the interest accrued on the senior notes and credit facilities up to April 27, 2016 (the date of the CCAA Initial Court Order), and amounts disclaimed on other Affected Creditors.

(2) The pro forma effect on common shares represents the estimated fair value of the common shares issued under the Restructuring Transaction, estimated at $17.63 per share, being the average cost of the shares acquired to fund the Cash Elections.

DIP Cash Collateral Account

On June 22, 2016, in accordance with the Restructuring Transaction, the funds related to the DIP Financing were deposited into a Canadian bank account in the name of the Company and were subject to a number of conditions, including the following;

- The Company was to maintain at all times prior to the completion of Restructuring Transaction a minimum unrestricted operating cash balance of $200 million.
- All unrestricted operating cash in excess of $100 million remaining in the Company's cash accounts excluding that which was in the DIP Cash Collateral Account at the end of each week was to be deposited into the DIP Cash Collateral account.
- If at the end of each week the unrestricted operating cash balance in the Company's cash accounts excluding that which was in the DIP Cash Collateral account was below $100 million, a withdrawal would be made from the DIP Cash Collateral Account in the amount required to return the balance to $100 million.

Upon completion of the Restructuring Transaction on November 2, 2016, the conditions associated with the DIP Cash Collateral Account were removed and the remaining cash balance was transferred back to the Company's operating accounts.

Colombian Affected Creditors Security

On June 10, 2016 the Superintendencia de Sociedades of Colombia (the "**Superintendencia**") granted an order under Ley 1116 recognizing the CCAA proceedings as the foreign main proceedings for the Restructuring Transaction. The Superintendencia also authorized the granting of security over the Colombian branches in connection with the DIP Financing and resolved that $50 million should be held in trust until the Restructuring Transaction was complete and as security for the Colombian Affected Creditors ("**Colombian Affected Creditors Security**"). The Company recognized the $50 million as current restricted cash as of September 30, 2016.

Upon completion of the Restructuring Transaction on November 2, 2016, the Colombian Affected Creditors Security was released. Consequently, the $50 million held in trust on behalf of Colombian creditors were returned to the Company, which in turn established a $39 million trust account in favour of Colombian trade creditors that had not yet been paid.

Restructuring Costs

During the three and nine months ended September 30, 2016, the Company incurred $26.8 million and $91.5 million, respectively, in costs related to the signing of forbearance agreements with its lenders and the Restructuring Transaction. These restructuring costs related predominantly to the appointment of independent financial advisors to assist with the ongoing negotiations and to counsel for all counterparties involved.

Included in restructuring costs is an accrual relating to retention bonuses for certain employees of the Company as part of the CCAA Initial Order.

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Highlights for the Third Quarter of 2016

Financial and Operating Summary

(in thousands of US$ except as noted)	Q3 2016	Q2 2016	Q3 2015	Nine Months Ended September 30 2016	Nine Months Ended September 30 2015
Operating activities					
Average sales volumes (boe/d)	**82,167**	110,024	141,492	104,173	154,792
Average oil and gas sales (boe/d)	**81,877**	109,736	139,270	103,864	145,323
Average trading sales (bbl/d)	**290**	288	2,222	309	9,469
Average net production (boe/d)	**75,096**	127,951	152,915	114,982	152,665
Average net production oil (bbl/d)	**67,128**	118,526	143,028	105,695	143,855
Average net production gas (boe/d)	**7,968**	9,425	9,887	9,287	8,810
Combined price ($/boe)	**40.83**	37.60	51.49	40.02	51.41
Combined netback ($/boe)	**18.90**	17.34	30.57	19.48	28.28
Combined operating cost ($/boe)	**21.93**	20.26	20.92	20.54	23.13
Capital expenditures	**30,061**	48,349	154,281	97,214	565,358
Financials					
Total oil and gas sales and trading sale ($)	**308,705**	376,403	669,995	1,141,939	2,172,576
Adjusted EBITDA (1)	**41,507**	100,356	271,569	305,575	848,407
Adjusted EBITDA margin (adjusted EBITDA/revenues)	**13%**	27%	41%	27%	39%
Funds flow from operations (1)	**10,934**	(5,664)	197,203	148,895	536,223
Funds flow from operations margin (funds flow from operations/revenues)	**4%**	-2%	29%	13%	24%
Net loss (2)	**(557,068)**	(118,654)	(617,318)	(1,576,671)	(1,565,951)

1. See “Additional Financial Measures” on page 33.
2.Net loss attributable to equity holders of the parent.

Breakdown of Oil & Gas and Trading Results

	Three Months Ended					
	September 30, 2016			September 30, 2015		
	Oil & Gas	Trading	Total	Oil & Gas	Trading	Total
Volume sold (boe/d)	**81,877**	**290**	**82,167**	**139,270**	**2,222**	**141,492**
Average realized price ($/boe)	**40.83**	**41.79**	**40.84**	**51.49**	**49.96**	**51.47**
Financial results (in thousands of US$)						
Revenues	**307,587**	**1,118**	**308,705**	**659,782**	**10,213**	**669,995**
Cost of operations	**165,212**	**905**	**166,117**	**268,085**	**9,660**	**277,745**
Production and purchase cost of barrels sold	72,694	905	73,599	94,567	9,660	104,227
Transportation cost (trucking and pipeline) [1]	71,360	-	71,360	142,236	-	142,236
Diluent cost	5,870	-	5,870	32,087	-	32,087
Other costs	15,269	-	15,269	12,361	-	12,361
Overlift/underlift	19	-	19	(13,166)	-	(13,166)
Gross margin	**142,375**	**213**	**142,588**	**391,697**	**553**	**392,250**

1. For the third quarter of 2016 and 2015, transportation costs on a boe basis include the Company's share of the income from equity investments in the ODL Finance S.A. ("**ODL**") and Oleoducto Bicentenario de Colombia ("**Bicentenario**") pipelines, which were a net of $16.3 million and $15.9 million, respectively. Refer to Note 15 of the Interim Condensed Consolidated Financial Statements for additional details.

Results

Operational

- For the third quarter of 2016, the Company's average daily net production after royalties was 75,096 boe/d, 41% and 51% lower compared with the previous quarter and the third quarter of 2015, respectively. The reduction was mainly attributable to the expiration of the Rubiales-Piriri contract on June 30, 2016.
- During the third quarter of 2016, the combined oil and gas operating cost before overlift and other costs was $19.90/boe, lower compared with $21.93/boe for the second quarter of 2016 and $20.98/boe in the third quarter of 2015, due to higher production cost but lower transportation and dilution costs. Total combined operating cost (including overlift, inventory movement, and other costs) was $21.93/boe, slightly higher when compared with $20.26/boe for the second quarter of 2016 and $20.92/boe of the third quarter of 2015, due to higher inventory movement and other costs.
- On September 27, 2016, the Company reached an agreement with Karoon Gas Australia Ltd. to sell its 35% working interest in the following concession agreements in Brazil S-M-1101, S-M-1102, S-M-1037, S-M-1165 and S-M 1166. The Company will receive from Karoon $15.5 million in cash as consideration on closing for its interests in the Karoon Blocks. In addition, the Company may receive a subsequent payment of $5 million on commercial production reaching 1 million barrels of oil or oil equivalents. The sale is is subject to Brazilian regulatory approval.
- On October 14, 2016, the Company and its Brazilian subsidiary entered into a farm-out agreement with Queiroz Galvão Exploração e Produção S.A. ("**QGEP**") for the transfer of the following participating interests in certain contracts from the Company's Brazilian subsidiary to QGEP: (i) 30% of Contract FZA-M-90; (ii) 50% of PAMA-M-337; and (iii) 70% of PAMA-M-265 (collectively, the "**Participating Interests**"). Pursuant to the agreement, the Company agreed to pay to QGEP the outstanding cash calls for these blocks in the amount of approximately R$51.7 million ($16 million). In addition, the Company's Brazilian subsidiary deposited $10 million into an escrow account to be released upon the satisfaction of certain conditions (including ANP, the Brazilian regulator's approval). Upon closing of this transaction, the Company expects to reduce its working commitments by approximately $25 million.

Financial

- Revenue for the third quarter totalled $309 million, $67 million lower as compared with the second quarter of 2016, reflecting lower volumes of sales during the quarter. Revenue decreased by $361 million from $670 million for the third quarter of 2015, mainly due to lower realized prices and the expiration of the Rubiales-Piriri contract.
- Total volume of oil and gas sales (including trading) for the third quarter of 2016 averaged 82,167 boe/d, 42% lower than the 141,492 boe/d in the third quarter of 2015 mainly due to the relinquishment of the Rubiales and Piriri fields in June 2016.
- Combined oil and gas operating netback for the quarter was $18.90/boe, 38% lower than the $30.57/boe in the third quarter of 2015, mainly attributable to the decline in market prices for crude oil. The Company's average sales price per barrel of crude oil and natural gas was $40.83/boe for the quarter, down from $51.49/boe in the same period of 2015.
- Adjusted EBITDA for the quarter was $42 million, compared to $100 million in the second quarter of 2016 and $272 million in the third quarter of 2015, with the decrease primarily due to lower volumes sold, and lower realized prices when compared with the third quarter of 2015.
- General and Administrative ("**G&A**") costs decreased to $42 million in the third quarter of 2016 from $53 million in the same period of 2015, as the Company continues to control G&A and all non-essential spending activities in light of the decrease in oil prices. In addition, while annualized SG&A (excluding severance and restructuring payments) has been reduced year over year by 29% during the course of the restructuring process, we are taking further steps to achieve a $110 million annualized expense in 2017, excluding one-time costs, compared to $221.5 million in 2015.
- Net loss attributable to equity holders of the parent was $557 million, largely due to $424 million of impairment recorded mainly on oil and gas, other assets and financial assets, lower sales due to the Rubiales-Piriri expiration contract, $27 million of costs related to the restructuring and finance cost of $23 million.
- Total capital expenditures decreased to $30 million in the third quarter of 2016, compared with $154 million in the same period of 2015.

3 Operating Netbacks

Oil & Gas Operating Netback

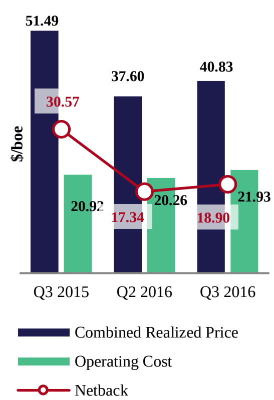
Our operating costs continued decreasing in 2016 as a result of strategies for streamlining production costs and optimizing field operations.

Combined operating netbacks during the three months ended September 30, 2016, June 30, 2016, and September 30, 2015 are summarized below.

	Three Months Ended						
	September 30, 2016			June 30, 2016			September 30, 2015
	Crude Oil	Natural Gas	Combined	Crude Oil	Natural Gas	Combined	Combined
Average daily volume sold (boe/day)[1]	**74,268**	**7,609**	**81,877**	**100,778**	**8,958**	**109,736**	**139,270**
Operating netback ($/boe)							
Crude oil and natural gas sales price	42.21	27.43	40.83	38.77	24.44	37.60	51.49
Production cost of barrels sold [2]	10.00	6.22	9.65	9.24	2.81	8.72	7.38
Transportation (trucking and pipeline) [3]	10.38	0.64	9.47	12.15	0.60	11.21	11.10
Diluent cost	0.86	-	0.78	2.18	-	2.00	2.50
Total operating cost	**21.24**	**6.86**	**19.90**	**23.57**	**3.41**	**21.93**	**20.98**
Other costs [4]	2.23	-	2.03	(1.81)	-	(1.66)	0.97
Overlift/underlift[5]	-	0.03	-	-	(0.13)	(0.01)	(1.03)
Total operating cost including overlift/underlift, and other costs	**23.47**	**6.89**	**21.93**	**21.76**	**3.28**	**20.26**	**20.92**
Operating netback crude oil and gas ($/boe)	**18.74**	**20.54**	**18.90**	**17.01**	**21.16**	**17.34**	**30.57**

1. Combined operating netback data is based on the weighted average of daily volume sold, which includes diluents necessary for the blending of heavy crude oil and excludes oil for trading volumes.
2. Cost of production mainly includes lifting cost and other direct production costs such as fuel consumption, outsourced energy, fluid transport (oil and water), personnel expenses, and royalties paid in cash, among others.
3. Includes the transport costs of transporting crude oil and gas through pipelines and tank trucks to delivery points, storage costs, and external road maintenance at the fields. For the three months ended September 30, 2016 and 2015, transportation cost included the Company's share of the income from equity investments in the ODL and Bicentenario pipelines.
4. Other costs mainly correspond to inventory fluctuation, and net effect of the currency hedges of operating expenses incurred in Colombian pesos for the three months ended September 30, 2015.
5. Corresponds to the net effect of the overlift position of $0.02 million expense during the third quarter of 2016 ($13 million income for the third quarter of 2015).

COMBINED OPERATING NETBACK



During the third quarter of 2016, the Company's average combined realized oil and gas price increased from $37.60/boe in the second quarter to $40.83/boe. The realized price for oil increased from an average of $38.77/bbl in the second quarter to an average of $42.21/bbl. The combined realized price has decreased compared with $51.49 for the same period in 2015, due to the decline in world crude prices.

After adapting to the low oil price environment in 2015, the Company continued to streamline operations to maintain cost efficiencies. Total operating costs, including production, transportation, and dilution costs, decreased from $21.93/boe in the second quarter of 2016 to $19.90/boe for the third quarter of 2016. Total combined operating costs increased from $20.26/boe in the second quarter of 2016 to an average of $21.93/boe for the third quarter of 2016. The increase in total cost was mainly a result of inventory movement during the period. During the third quarter of 2016, the Bicentenario pipeline was not operational for an average of 74 days; however, the Company was able to source available operational capacity to the OCENSA pipeline at comparable costs per unit.

During the third quarter of 2016, the combined oil and gas operating netback was $18.90/boe, $1.56/boe higher than the second quarter of 2016 ($17.34/boe), mainly driven by a slight recovery in realized prices. The crude oil operating netback specifically was $18.74/bbl, 10% higher as compared to the second quarter of 2016.

Combined operating netbacks for the nine months ended on September 30, 2016 and 2015 are summarized below.

	Nine Months Ended September 30					
	2016			2015		
	Crude Oil	Natural Gas	Combined	Crude Oil	Natural Gas	Combined
Average daily volume sold (boe/day)[1]	**94,943**	**8,921**	**103,864**	**136,561**	**8,762**	**145,323**
Operating netback ($/boe)						
Crude oil and natural gas sales price	41.37	25.62	40.02	52.61	32.63	51.41
Production cost of barrels sold [2]	9.49	4.07	9.02	8.85	4.35	8.58
Transportation (trucking and pipeline) [3]	12.20	0.37	11.18	12.42	0.60	11.71
Diluent cost	1.99	-	1.82	2.14	-	2.01
Total operating cost	**23.68**	**4.44**	**22.02**	**23.41**	**4.95**	**22.30**
Other costs [4]	(0.28)	-	(0.26)	0.89	-	0.83
Overlift/underlift[5]	(1.33)	(0.10)	(1.22)	0.01	(0.04)	-
Total operating cost including overlift/underlift, and other costs	**22.07**	**4.34**	**20.54**	**24.31**	**4.91**	**23.13**
Operating netback crude oil and gas ($/boe)	**19.30**	**21.28**	**19.48**	**28.30**	**27.72**	**28.28**

Notes: Refer to the operating netback table on page 8.

During the nine months ended September 30, 2016, combined crude oil and gas operating netback was $19.48/boe, $8.80/boe lower than the same period of 2015 ($28.28/boe). Crude oil netback was $19.30/bbl, $9.00/bbl lower than the same period of 2015 ($28.30/bbl). Both the combined and crude oil netbacks were impacted by the decline in world crude prices during the period, resulting in a 22% decrease in combined realized price to $40.02/boe for the nine months ended September 30, 2016 from $51.41/boe in same period of 2015. At the same time, the Company achieved a reduction in total operating costs (including overlift/underlift and other costs) of $2.59/boe from $23.13/boe to $20.54/boe. Reductions in field costs were achieved through a number of initiatives, including streamlining of the workforce.

Trading Netback

	Three Months Ended		
Crude oil trading	**September 30 2016**	**June 30 2016**	**September 30 2015**
Average daily volume sold (bbl/d)	**290**	**288**	**2,222**
Operating netback ($/bbl)			
Crude oil traded sales price	41.79	36.79	49.96
Cost of purchases of crude oil traded	33.83	25.35	47.26
Operating netback crude oil trading ($/bbl)	**7.96**	**11.44**	**2.70**

In the third quarter of 2016, the Company traded an average of 290 bbl/d compared with 2,222 bbl/d in the same period of 2015. The average netback for volumes traded in the third quarter of 2016 was $7.96/bbl (a gross margin of $0.2 million) versus the netback obtained in the same period of 2015 of $2.70/bbl (a gross margin of $0.5 million). The drop in the volumes sold in 2016 was mainly attributable to the reduction in oil production in Colombia, which allowed other traders to utilize the available capacity in pipelines to be more competitive.

The nature of the Company's oil trading business is opportunistic and often depends on the available capacity under the pipeline transportation agreements. The Company's ability to acquire crude oil for trading purposes allows it to use any available capacity and offset the take-or-pay transport fees.

4 Operational Results

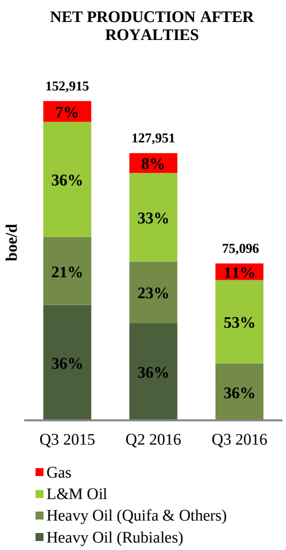
Production and Development Review

During the third quarter of 2016, net production after royalties and internal consumption totalled 75,096 boe/d, a decrease of 52,855 boe/d (41%) from the average net production of 127,951 boe/d reported in the second quarter of 2016. This reduction is mainly attributable to the Rubiales and Piriri fields, both of which were returned to Ecopetrol on June 30, 2016, upon the expiration of the joint operating agreements.

During the third quarter of 2016, heavy oil production from Quifa and other fields decreased by 8% compared with the previous quarter, mainly due to operational issues with water disposal capacity. Light and medium net oil production in Colombia and Peru totalled 39,947 bbl/d, decreasing by 6% from the second quarter of 2016 (42,453 bbl/d). The decrease is mainly attributable to the natural decline of the Llanos oil fields, which have not been sustained by drilling activity. Light and medium oil and heavy oil production (excluding production at the Rubiales field) now represent 53% and 36%, respectively, of total net oil and gas production. Additionally, gas production decreased 15% compared with the previous quarter due to operational issues.

The following table highlights the average daily production from all of the Company's producing fields in Colombia and Peru.

Third Quarter 2016 Production



	Average Production (in boe/d)						
	Total field production		Gross share before royalties [1]		Net share after royalties		
Producing fields in Colombia	**Q3 2016**	**Q3 2015**	**Q3 2016**	**Q3 2015**	**Q3 2016**	**Q2 2016**	**Q3 2015**
Rubiales / Piriri	-	164,865	-	68,977	-	46,483	55,182
Quifa SW [2]	44,934	55,176	26,692	32,808	24,299	26,430	29,040
	44,934	**220,041**	**26,692**	**101,785**	**24,299**	**72,913**	**84,222**
Other fields in Colombia							
Light and medium [3]	41,986	56,598	39,599	53,606	37,765	40,352	49,843
Gas [4]	8,884	10,945	7,968	9,887	7,968	9,425	9,887
Heavy oil [5]	4,000	5,429	3,008	3,718	2,882	3,160	3,552
	54,870	**72,972**	**50,575**	**67,211**	**48,615**	**52,937**	**63,282**
Total production Colombia	**99,804**	**293,013**	**77,267**	**168,996**	**72,914**	**125,850**	**147,504**
Producing fields in Peru							
Light and medium [6]	5,628	9,741	2,182	5,411	2,182	2,101	5,411
	5,628	**9,741**	**2,182**	**5,411**	**2,182**	**2,101**	**5,411**
Total production Colombia and Peru	**105,432**	**302,754**	**79,449**	**174,407**	**75,096**	**127,951**	**152,915**

1. Share before royalties is net of internal consumption at the field and before PAP at the Quifa SW field.
2. The Company's share before royalties in the Quifa SW field is 60% and decreases in accordance with a high-price clause (PAP) that assigns additional production to Ecopetrol.
3. Mainly includes Cubiro, Cravoviejo, Casanare Este, Canaguaro, Guatiquia, Casimena, Corcel, CPI Neiva, Cachicamo, Arrendajo and other producing fields.
4. Includes La Creciente, Dindal/Rio Seco, Cerrito, and Guama fields.
5. Includes Cajua, Sabanero, CPE-6, Rio Ariari, Prospecto S and Prospecto D fields. Subject to approval from Agencia Nacional de Hidrocarburos ("**ANH**"), the Company is in the process of acquiring the remaining 50% participation in the CPE-6 field.
6. Includes Block 192, which has been operating since August 30, 2015, with 12,000 bbl/d of gross production under normal conditions.

Colombia

The Company continues to operate fields and facilities to maximize production while minimizing capital expenditures. Net production after royalties in Colombia was 72,914 boe/d (99,804 boe/d total field production) for the third quarter of 2016, down from 147,504 boe/d (293,013 boe/d total field production) in the same period of 2015, and 42% lower than 125,850 boe/d in the second quarter of 2016 (246,626 boe/d total field production).

The Company and Ecopetrol signed a termination agreement for the return of the Rubiales and Piriri fields upon the expiration of the contract on June 30, 2016. Both parties were actively involved to ensure a smooth transition of the operatorship. Pursuant to the Rubiales-Piriri contract, all fixed assets located in these fields were transferred to Ecopetrol along with the operatorship without compensation. Therefore, all net book value of fixed assets associated with these fields has been fully depleted. As part of the settlement, a volume of 189,776 bbl of crude oil inventory, which had been booked during the prior quarter, was physically transferred to the Company during the third quarter of 2016. This volume became part of the sales for the third quarter.

Peru

The Company's production from Peru consists of a 49% participating interest in Block Z-1, a 30% working interest in the Los Angeles discovery in Block 131, and the Block 192 services contract. Net production after royalties for the third quarter of 2016 totalled 2,182 bbl/d, a 4% increase from 2,101 bbl/d in the second quarter of 2016.

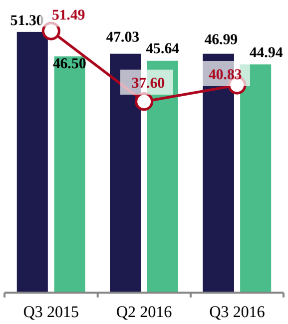
Sales, Trading and Pricing

The following table highlights the average daily crude oil and gas available for sale, and realized and international prices.

	Average Volume of Sales and Prices		
Colombia and Peru	**Q3 2016**	**Q2 2016**	**Q3 2015**
Oil (bbl/d)	75,750	101,855	132,492
Gas (boe/d)	7,609	8,958	9,679
Trading (bbl/d)	290	288	2,222
Total barrels sold (boe/d)	**83,649**	**111,101**	**144,393**
Sales from E&E assets (boe/d) (1)	(1,482)	(1,077)	(2,901)
Net barrels sold (in boe/d)	**82,167**	**110,024**	**141,492**
Realized prices			
Oil realized price ($/bbl)	42.21	38.77	52.94
Gas realized price ($/boe)	27.43	24.44	32.17
Combined realized price oil and gas $/boe (excluding trading)	40.83	37.60	51.49
Trading realized price ($/bbl)	41.79	36.79	49.96
Reference market prices			
WTI NYMEX ($/bbl)	44.94	45.64	46.50
ICE BRENT ($/bbl)	46.99	47.03	51.30
Guajira gas price ($/MMBtu) (2)	5.93	5.93	5.08
Henry Hub average natural gas price ($/MMBtu)	2.25	2.25	2.73

1. Includes sales from exploration and evaluation assets.
2. The domestic natural gas sales price is referenced to the Market Reference Price ("**MRP**") for gas produced in La Guajira field. Reference: Official circulars 002 and 090 of 2014, Energy and Gas Regulatory Commission ("**CREG**") and the inform of the results for the commercialization process of 2015 by the market operator, as defined in CREG Resolution 089, 2013.

PRICES



** Excluding Trading*

During the three months ended September 30, 2016, average oil and gas sales (including trading) totalled 82,167 boe/d, a decrease of 42% from the 141,492 boe/d in the same period of 2015, mainly due to the Rubiales-Piriri expiration contract and natural oil production declines.

The crude oil and gas combined realized price for the three months ended September 30, 2016, reached $40.83/boe, $10.66/boe lower than the same period of 2015.

For the third quarter of 2016, the WTI NYMEX price decreased by $1.56/bbl (3%) to an average of $44.94/bbl, compared with the average of $46.50/bbl in the same period of 2015. Likewise, the ICE BRENT price declined by $4.31/bbl (8%) to an average of $46.99/bbl, compared with the average of $51.30/bbl in the same period of 2015.

5 Financial Results

Revenues

	Three Months Ended September 30		Nine Months Ended September 30	
(in thousands of US$)	2016	2015	2016	2015
Net crude oil and gas sales	$ 307,587	$ 659,782	$ 1,138,941	$ 2,039,461
Trading revenue	1,118	$ 10,213	2,998	133,115
Total sales	**$ 308,705**	**$ 669,995**	**$ 1,141,939**	**$ 2,172,576**
$ per boe oil and gas	40.83	51.49	40.02	51.41
$ per bbl trading	41.79	49.96	35.44	51.49
$ Total average revenue per boe	**40.84**	**51.47**	**40.01**	**51.41**

The following is an analysis of the price and sales volume movements for the third quarter of 2016 in comparison with the same period of 2015.

	Three Months Ended September 30			
	2016	2015	Difference	Change (%)
Total of boe sold (Mboe)	7,559	13,017	(5,458)	(42)
Avg. combined price – oil & gas and trading ($/boe)	40.84	51.47	(10.63)	(21)
Total revenue	**$ 308,705**	**$ 669,995**	**$ (361,290)**	(54)

Drivers for the revenue decrease:		
Due to volume	$ (280,918)	78%
Due to price	(80,372)	22%
	$ (361,290)	

During the third quarter of 2016, revenues totalled $309 million, 54% less than the same period of 2015, wherein revenues totalled $670 million. This decrease is the result of the Rubiales-Piriri expiration contract, lower volumes sold and lower realized oil prices.

Revenue for the nine months ended September 30, 2016, were $1,142 million, 47% less than the same period of 2015, which had revenues of $2,173 million.

Operating Costs

	Three Months Ended September 30		Nine Months Ended September 30	
(in thousands of US$)	2016	2015	2016	2015
Production cost of barrels sold	$ 72,694	$ 94,567	$ 256,716	$ 340,347
Per boe	9.65	7.38	9.02	8.58
Transportation cost [1]	71,360	142,236	318,139	464,432
Per boe [1]	9.47	11.10	11.18	11.71
Diluent cost	5,870	32,087	51,823	79,796
Per boe	0.78	2.50	1.82	2.01
Other cost	15,269	12,361	(7,306)	33,049
Per boe	2.03	0.97	(0.26)	0.83
Overlift/underlift	19	(13,166)	(34,816)	121
Per boe	-	(1.03)	(1.22)	-
Operating cost	**$ 165,212**	**$ 268,085**	**$ 584,556**	**$ 917,745**
Average operating cost per boe	**$ 21.93**	**$ 20.92**	**$ 20.54**	**$ 23.13**
Take-or-pay fees on disrupted transport capacity Bicentenario	43,032	51,722	86,481	81,999
Per boe	5.71	4.04	3.04	2.07
Trading purchase cost	905	9,660	2,411	126,423
Per bbl	33.83	47.25	28.50	48.90
Total cost	**$ 209,149**	**$ 329,467**	**$ 673,448**	**$ 1,126,167**

1. For the three months ended September 30, 2016 and 2015, transportation costs on a boe basis include the Company's share of the income from equity investments in the ODL and Bicentenario pipelines, which were a net of $16.3 million and $15.9 million, respectively. Refer to Note 15 of the Interim Condensed Consolidated Financial Statements for additional details.

Total operating costs for the third quarter of 2016 were $209 million, a value which includes the Company's $16.3 million share of income from equity investments in the ODL and Bicentenario pipelines and $43 million ($5.71/boe) in net take-or-pay fees paid to Bicentenario for unavailable capacity. When operations at the Bicentenario pipeline were suspended for 74 days for security issues, the Company used a combination of trucking and available capacity on the OCENSA pipeline to move oil to the export ports.

For the third quarter of 2016, total operating costs were $209 million, a 37% decrease from the $329 million for the same period of 2015. The reduction in costs resulted from cost optimization strategies adopted as a response to the lower oil price environment.

In addition, trading purchase costs decreased from $10 million in the third quarter of 2015 to $1 million in the third quarter of 2016, mainly due to lower sales volumes.

Depletion, Depreciation and Amortization

	Three Months Ended September 30				Nine Months Ended September 30			
(in thousands of US$)	2016		2015		2016		2015	
Depletion, depreciation and amortization	$	113,802	$	344,577	$	490,285	$	1,148,735
$/per boe sales (own production)		15.11		26.89		17.23		28.95

For the third quarter of 2016, DD&A costs were $114 million, compared to $345 million for the same period of 2015. The 67% decrease is primarily due to the lower carrying amount of oil and gas properties resulting from the impairments recognized during 2014, 2015 and the first quarter of 2016. The decrease is also due to full depletion of the assets associated with the Rubiales-Piriri contracts upon termination of the contract on June 30, 2016. Unit DD&A for the third quarter of 2016 was $15.11/boe, 44% lower than the $26.89/boe for the same period of 2015. During the nine months ended as of September 30, 2016, oil and gas assets were depleted over the Company's proved reserves (2015: proved and probable reserves).

Impairment and Exploration Expenses

	Three Months Ended September 30				Nine Months Ended September 30			
(in thousands of US$)	2016		2015		2016		2015	
Impairment of oil & gas properties and plant and equipment	$	281,272	$	356,000	$	885,270	$	593,009
Impairment of exploration and evaluation assets		13,115		74,000		45,941		275,000
Impairment of other assets		129,526		-		182,388		10,958
Exploration expenses		-		138,013		-		138,013
Total impairment	**$**	**423,913**	**$**	**568,013**	**$**	**1,113,599**	**$**	**1,016,980**

At the end of each reporting period, the Company assesses whether there is any indication, from external and internal sources of information, that an asset or cash generating unit ("**CGU**") may be impaired. Information the Company considers includes changes in the market, economic and legal environment in which the Company operates that are not within its control and affect the recoverable amount of oil and gas, exploration and evaluation properties.

The Company's impairment tests of oil and gas, exploration, and evaluation assets are performed at the CGU level. The recoverable amount is calculated based on the higher of value-in-use and fair value less cost-to-sell. The recoverable amount as of September 30, 2016, was determined based on the fair value less cost-to-sell (2015: value-in-use).

During the third quarter of 2016, the Company identified indicators of impairment in two oil and gas producing CGUs, due to an internal change in reserve estimation in the North Colombia CGU, and a change in operating cost and cash flow assumptions related to the Peru CGU primarily as a result of ongoing pipeline downtimes. As a result, the Company performed a test for recoverability for these CGUs and has recorded an impairment charge for oil and gas properties of $172.4 million in the North Colombia CGU and $44 million in the Peru CGU, respectively. The impairment in the North Colombia CGU is due to a water breakthrough into the La Creciente 3ST wellbore that occurred in the third quarter. While breakthroughs are expected in water-driven reservoirs, this one led the Company to reassess the geological model and the dynamic interaction between the aquifer and the reservoir and their impact, which resulted in a revision to the reservoir volumetric estimates on a preliminary basis. The analysis of the long-term effect of the water encroachment on reserves and production will continue for some time; as a result, the Company made an estimate of the recoverable amount as of September 30, 2016 based on currently available information. The completion of the analysis of the encroachment may materially change the current reservoir volumetric estimate.

During the third quarter of 2016, the Company also performed impairment tests in two separate CGUs related to certain properties connected to power transmission and water irrigation, and an impairment charge for oil and gas properties of $64.9 million for these CGUs.

During the third quarter of 2016, as a result of the Company's limited ability to fund future exploration and evaluation assets, an impairment charge of $13.1 million was recognized in respect of minimum required exploration expenses incurred.

The Company had certain advances with the Bicentenario and other pipelines that could be used against future transportation of crude in either 2025 or when certain contracted capacity limits are met. As of September 30, 2016, based on updated production forecasts, the Company believed these advances would not be utilized, and as a result, the balance of $54.0 million has been fully impaired.

The Company has recorded an impairment charge of $75.6 million relating to certain receivables as of September 30, 2016, the majority of which related to VAT receivable in Peru. As a result of updating the production forecasts, the Company determined that it was more likely than not that the VAT receivable in Peru would not be recovered through future productions on certain blocks.

General and Administrative Costs

	Three Months Ended September 30		Nine Months Ended September 30	
(in thousands of US$)	2016	2015	2016	2015
General and administrative costs	$ 41,705	$ 53,079	$ 113,204	$ 159,088
$/per boe sales	5.52	4.08	3.97	3.76

G&A costs decreased to $42 million in the third quarter of 2016 from $53 million in the same period of 2015, mainly due to the adoption of cost optimization initiatives. G&A costs per boe increased by $1.44/boe to $5.52/boe from $4.08/boe in the same period of 2015, due to the decrease in sales volume during the period.

Restructuring Costs

	Three Months Ended September 30		Nine Months Ended September 30	
(in thousands of US$)	2016	2015	2016	2015
Restructuring costs	$ 26,795	$ -	$ 91,515	$ -

During the three and nine months ended September 30, 2016, the Company incurred $27 million and $92 million in costs related to the Restructuring Transaction.

Finance Costs and Foreign Exchange

	Three Months Ended September 30		Nine Months Ended September 30	
(in thousands of US$)	2016	2015	2016	2015
Finance costs	$ 22,943	$ 71,954	$ 124,748	$ 228,929

Finance costs include interest on the Company's bank loans, senior notes, revolving credit facilities, working capital loans, finance leases, fees on letters of credit, net of interest income received, and for 2016 only, interest on the Company's DIP Financing. For the three months ended September 30, 2016, finance costs totalled $23 million, less than the $72 million in the same period of 2015, mainly as a result of the senior notes and the credit facilities ceasing to accrue interest on April 27, 2016, when the Company received the Initial Order for the Restructuring Transaction.

(in thousands of US$)	Three Months Ended September 30 2016	2015	Nine Months Ended September 30 2016	2015
Foreign exchange gain (loss)	$ 17,541	$ (71,887)	$ 22,720	$ (113,081)

Foreign exchange gains or losses primarily result from the movement of the Colombian peso ("**COP**") against the U.S. dollar. A significant portion of the Company's working capital and expenditures are denominated in COP. During the third quarter of 2016, the COP appreciated against the U.S. dollar by 1.2%, compared with a depreciation of 20.8% during the same period of 2015. Foreign exchange gain for the three months ended September 30, 2016, was $18 million, compared with a loss of $72 million in the same period of 2015, primarily due to the impact the appreciation of the COP had on the translation of the Company's net working capital.

Income Tax Expense

(in thousands of US$)	Three Months Ended September 30 2016	2015	Nine Months Ended September 30 2016	2015
Current income tax	$ (21,321)	$ (12,124)	$ (41,409)	$ (42,317)
Deferred income tax: Relating to origination and reversal of temporary differences	940	46,317	2,456	150,162
Total income tax (expense) recovery	**$ (20,381)**	**$ 34,193**	**$ (38,953)**	**$ 107,845**

The Canadian statutory combined income tax rate was 26.5% for the third quarter of 2016 and 2015.

The Colombian statutory tax rate for the third quarter of 2016 was 40% (2015: 39%), which includes the 25% general income tax rate and the fairness tax ("**CREE**") of 15% (2014: 14%). The Colombian Congress enacted new corporate tax rates for Colombian source income that are set to 40% in 2016, 42% in 2017 and 43% in 2018. As of January 1, 2019, the corporate tax rate will be reduced to 34%.

In addition, Congress introduced a temporary new wealth tax that accrues on net equity as of January 1, 2016, and 2017 at 1.00% and 0.40%, respectively.

The Peruvian statutory income tax rate was 28% and 30% for the quarters ended September 30, 2016 and 2015, respectively. The Peruvian income tax rate for Block Z-1 was 22% for the quarters ended September 30, 2016 and 2015. The Peruvian government passed major tax reforms on December 31, 2014, including a reduction in the general corporate tax rate to 28% for 2016, 27% for 2017 and 2018 and 26% for taxation years 2019 and onwards.

The Company's effective tax rate differs from the statutory rate due to:

- Expenses that are not deductible for tax purposes (such as share-based compensation, foreign exchange gains or losses and other non-deductible expenditures in both Canada and Colombia, and the impairment losses in Colombia).
- Corporate expenses that result in tax loss carry-forwards; however, no deferred tax assets or recovery have been recognized. When the Company has a reasonable expectation to utilize these losses in the future, a deferred tax asset and a corresponding deferred tax recovery may be recognized, which would reduce the income tax expense.
- Foreign currency exchange rate fluctuations. The Company's functional and reporting currency is the U.S. dollar; however, the calculation of the income tax expense is based on income in the currency of the country of origin (i.e., Colombia), where the Company's assets are primarily located. As a result, the tax base of these assets is denominated in COP, and the related deferred tax balances are continually subject to fluctuations in the U.S.-COP exchange rate for IFRS purposes.
- The appreciation of the COP against the U.S. dollar by 1.24% during the third quarter of 2016, which resulted in an estimated unrealized deferred income tax expense of $0.07 million. In comparison, the Company recorded $223.5 million of unrealized deferred income tax expense during the same period of 2015 as a result of the depreciation of the COP against the U.S. dollar by 20.8%.

Excluding the effect from the above-mentioned foreign exchange fluctuations, the effective tax rate for the Company was negative (3.8%) and 38.9% for the three months ended September 30, 2016 and 2015, respectively.

(in thousands of US$)	Three Months Ended September 30 2016	2015	Nine Months Ended September 30 2016	2015
Appreciation (depreciation) of the COP against the U.S. dollar	1.24%	(20.8)%	8.6%	(30.5)%
Net loss before income tax	(538,991)	(663,210)	(1,527,515)	(1,674,643)
Current income tax expense	(21,321)	(12,124)	(41,409)	(42,317)
Deferred income tax	940	46,317	2,456	150,162
Total income tax (expense) recovery as reported	**(20,381)**	**34,193**	**(38,953)**	**107,845**
Excluding effect from depreciation of COP	-	223,531	-	363,397
Total income tax (expense) recovery excluding the above effects	**(20,381)**	**257,724**	**(38,953)**	**471,242**
Effective tax rate excluding effect of COP apreciation/depreciation	**(3.8)%**	**38.9%**	**(2.6)%**	**28.1%**

During the third quarter of 2016, the Company did not recognize any deferred tax relating to foreign exchange fluctuations; therefore, the Company is not reflecting these fluctuations in the deferred tax calculation.

Current income tax in Colombia totalled $23.5 million in the nine months ended September 30, 2016 as compared to $42.1 million in the nine months ended September 30, 2015. The reduction is mainly attributable to Colombian entities subject to a minimum income tax (presumptive income) and a write-off for income tax receivables of $17 million and previous year adjustments of $1.5 million.

The 2016 wealth tax paid totalled $26 million. Based on the Company's taxable base, the Company will not make an accrual for future years, pursuant to IAS 37 and IFRIC 21.

Capital Expenditures

(in thousands of US$)	Three Months Ended September 30 2016	2015	Nine Months Ended September 30 2016	2015
Production facilities	$ 4,691	$ 24,789	$ 24,517	$ 85,272
Exploration activities	5,978	46,271	28,504	153,388
Early facilities and others	1,043	1,793	3,502	3,642
Development drilling	16,873	73,213	32,488	287,065
Other projects	1,476	8,215	8,203	35,991
Total capital expenditures	**$ 30,061**	**$ 154,281**	**$ 97,214**	**$ 565,358**

Capital expenditures during the third quarter of 2016 totalled $30 million, $124 million lower than the $154 million in the third quarter of 2015. A total of $5 million was invested in the expansion and construction of production infrastructure, primarily in the Quifa SW, Arrendajo, Cubiro, Cravoviejo, Guatiquia, La Creciente, Corcel, Orito, Neiva and Block Z-1 fields; $6 million went into exploration activities mainly invested in Brazil; $1 million went into facilities and others; $17 million went into development drilling; and $1 million was invested in other projects.

In light of the current weak commodity price environment, since the second half of 2015 our capital expenditure programs have been cut back significantly to focus on high impact development drilling and minimum committed capital programs.

Financial Position

Debts and Credit Instruments

The following debts were outstanding as at September 30, 2016. The senior notes and the credit facilities ceased to accrue interest on April 27, 2016 as a result of the Company receiving the Initial Order for the Restructuring Transaction.

Subsequent to the third quarter of 2016, the Company's capital structure was changed significantly on the successful completion of the Restructuring Transaction on November 2, 2016, and the elimination of substantially all of the Company's debts. Refer to "Restructuring Transaction" on page 1.

Senior Unsecured Notes

The Company had a number of series of senior unsecured notes outstanding with an aggregate principal of $4.1 billion as at September 30, 2016. The senior notes were listed on the Official List of the Luxembourg Stock Exchange and guaranteed by the Company's main operating subsidiaries. The maturities of the senior notes ranged from 2019 to 2025, and the interest rates ranged from 5.125% to 7.25%, payable semi-annually.

Pursuant to the indentures governing the senior notes, the financial covenant prohibiting the incurrence of additional indebtedness of 3.5 times consolidated debt-to-EBITDA was breached in 2015, which limited the Company's ability to incur additional debt, subject to various exceptions, including certain refinancing transactions.

Credit Facilities

As at September 30, 2016, the Company had the following credit facilities outstanding:

- $1 billion in principal under a revolving credit facility with a syndicate of lenders;

- $2.9 million in principal under the Bank of America loan, which carries an interest rate of LIBOR + 1.5% and matures in November 2016, with interest payments due biannually; and

- $212.5 million in principal under the HSBC facility, which carries an interest rate of LIBOR + 2.75% and matures in 2016 ($62.5 million) and 2017 ($150 million).

Under the terms of the revolving credit facility and the Bank of America and HSBC facilities, the Company was required to comply with certain "maintenance-based" financial covenants. Specifically, the Company was required to maintain an interest coverage ratio of greater than 2.5; a debt-to-EBITDA ratio of less than 4.5; and a net worth greater than $1 billion. Net worth was calculated as total assets less total liabilities, excluding those of the excluded subsidiaries, Pacific Midstream Ltd. and Pacific Infrastructure Ventures Inc. The Company was in breach of the interest coverage covenant, the debt-to-EBITDA covenant and the net worth covenant during the period.

Letters of Credit

As at September 30, 2016, the Company had issued letters of credit and guarantees for exploration and operational commitments for a total of approximately $167 million.

Other than the Exit Notes, the Exit LC Facility, certain finance leases for power generation and equipment and the hedging facility with BP Products North America Inc., the Company does not maintain any other indebtedness. The Exit Notes and Exit LC Facility provide certain exemptions pursuant to which the Company may incur additional indebtedness.

Oil Price Hedging

During the third quarter of 2016, the Company entered into several oil price risk management contracts to hedge against oil price volatility through April 2017. The hedges consisted of zero-cost collars. As at September 30, 2016, the Company had hedge positions for approximately 6.4 million barrels with floor and ceiling strike prices of $42.5/bbl and $57.0/bbl ICE Brent, respectively.

There were no realized gains from oil price hedging activity for the quarter. The estimated market value of the hedges as of September 30, 2016, was a liability of $18.5 million.

In addition to risk management contracts, the Company also entered into a forward-sale contract with a floor price of $46.0/bbl and a ceiling of $49.6/bbl ICE Brent (subject to a price differential on the ICE Brent), whereby the Company shall deliver 500,000 bbl per month from September 2016 until February 2017.

Outstanding Share Data

Common shares

As at November 10, 2016, 50,002,537 common shares were issued and outstanding.

The Company does not have shares subject to escrow restrictions or pooling agreements.

Deferred share units

As at November 14, 2016, there were 15,392 DSUs outstanding. DSUs are instruments that may be settled in cash or common shares that track the price of the common shares and are payable to eligible participants (being limited to directors of the Company) upon their departure from the Board of Directors of the Company.

Liquidity and capital resources

As at September 30, 2016, the Company had negative working capital of $5,681 million, mainly comprised of $556 million in cash and cash equivalents, $76 million in restricted cash, $170 million in accounts receivable, $42 million in inventory, $83 million in income tax receivable, $4 million in prepaid expenses, $764 million in accounts payable and accrued liabilities, $19 million risk-management liability, $9 income tax payable, $5,815 million in loans and borrowings, $3 million in the current portion of obligations under finance lease and $2 million in asset retirement obligations.

Funds flow provided by operating activities for the third quarter of 2016 totalled $11 million (2015: $197 million). The decrease in funds flow in 2016 compared with the same period of 2015 was mainly the result of a decrease in oil prices, production reduction and the Rubiales-Piriri expiration contract.

Refer to "Risks and Uncertainties" on page 36 for details of the risks and uncertainties relating to the Company's liquidity and capital resources.

6 Commitments and Contingencies

Tax Review in Colombia

The Colombian tax authority DIAN has officially reassessed several value-added tax ("**IVA**") declarations on the basis that the volume of oil produced and used for internal consumption at certain fields in Colombia should have been subject to IVA. For the nine months ended September 30, 2016, the amount reassessed, including interest and penalties, is estimated at $65.6 million, of which the Company estimates that $23 million should be assumed by companies that share interests in these contracts. The Company disagrees with the DIAN's reassessment, and official appeals have been initiated.

On February 24 and August 10, 2016, the DIAN released two general rulings to third parties, which concluded that the internal consumption of oil produced does not create an IVA obligation. The Company expects the current dispute regarding IVA to be resolved in its favour, and as such no provision has been recognized in the interim condensed consolidated financial statement.

The Company continues to utilize oil produced for internal consumption, which is an accepted practice for the oil industry in Colombia.

The DIAN is also reviewing certain income tax deductions with respect to the special tax benefit for qualifying petroleum assets as well as other exploration expenditures. As at September 30, 2016, the DIAN has reassessed $70.9 million of tax owing, including estimated interest and penalties, with respect to the denied deductions.

As at September 30, 2016, the Company believes that the disagreements with the DIAN related to the denied income tax deductions will be resolved in favour of the Company. No provision with respect to income tax deductions under dispute has been recognized in the interim condensed consolidated financial statements.

Equity tax

Effective January 1, 2015, the Colombian Congress introduced a new wealth tax that is calculated on a taxable base (net equity) in excess of COP$1 billion ($0.4 million) as at January 1 of the applicable taxation year (2015). The applicable rates for January 1, 2015, 2016 and 2017 are 1.15%, 1.00% and 0.40%, respectively. Based on the Company's taxable base, the Company has accrued a liability for the 2016 fiscal year. Pursuant to IAS 37 and IFRIC 21, in the current year, the Company has not made an accrual for future years. The 2016 wealth tax has been estimated at $26.9 million and recorded as an expense in the statement of loss (2015: $39.1 million). In May 2016, the Company made the first payment of $12.8 million (2015: $20.5 million) and in September 2016, the Company made the second payment for the remaining $14.1 million (2015: $18.6 million).

High-Price Royalty in Colombia

The Company is currently in discussion with the ANH with respect to the interpretation of the high-price participation clause in certain exploration contracts. Please refer to "PAP Disagreement with the ANH" on page 31 for details relating to this contingency.

Minimum Credit Rating Requirement

The Company has an assignment agreement with Transporte Incorporado S.A.S. ("**Transporte Incorporado**"), a Colombian company owned by an unrelated international private equity fund. Transporte Incorporado owns a 5% equity interest and capacity right in the OCENSA pipeline in Colombia. Under the assignment agreement, the Company is entitled to use Transporte Incorporado's capacity to transport crude oil through the OCENSA pipeline for a set monthly premium until 2024. Pursuant to the assignment agreement, the Company is required for the duration of the agreement to maintain a minimum credit rating of Ba3 (Moody's), which was breached in September and December 2015 and January 2016 when Moody's downgraded the Company's credit rating to B3, Caa3 and C respectively. As a result of the downgrade and in accordance with the assignment agreement, upon giving notice to the Company, Transporte Incorporado would have the right to terminate the assignment agreement early and the Company would be required to pay an amount determined in accordance with the agreement, estimated at $129 million. The Company has not received such notice from Transporte Incorporado, and on January 6, 2016, the Company received a waiver from Transporte Incorporado of its right to early-terminate for a period of 45 days until February 15, 2016, which was further extended several times to March 2019. The Company continues to pay monthly premiums and is currently in negotiation with Transporte Incorporado regarding the terms of the agreement and the minimum credit rating requirement. No provision has been recognized as of September 30, 2016, relating to the breach of the credit rating requirement.

In Colombia, the Company is participating in a project to expand the OCENSA pipeline, which is expected to be completed and commence operation later in December 2016. As part of the expansion project, the Company, through its subsidiaries Meta Petroleum and Petrominerales Colombia, entered into separate crude oil transport agreements with OCENSA for future transport capacity. The Company will start paying ship-or-pay fees once the expansion project is complete and operational. As part of the transport agreements, the Company is required to maintain minimum credit ratings of BB- (Fitch) and Ba3 (Moody's). This covenant was breached in September and December 2015 and January 2016 when Moody's downgraded the Company's credit rating to B3, Caa3, and C, respectively. As a result of the downgrades and pursuant to the transport agreements, upon giving notice to the Company, OCENSA has the right to require the Company to provide a letter of credit or proof of sufficient equity or working capital within a cure period of 60 days starting from the day on which notice is received by the Company. On November 5, 2015, the Company received a waiver from OCENSA of its right to receive a letter of credit, which will expire once the project is complete and operational. No provision has been recognized as of September 30, 2016, relating to the breach of the credit rating requirement.

Upon completion of the Restructuring Transaction, the Company received ratings upgrades from Fitch to B (B+ on the Exit Notes) and from Standard & Poors to B+. It has not yet received any indication from Moody's as to whether that organization will be changing the Company's rating due to the completion of the Restructuring Transaction.

Commitments

The Company is involved in various claims and litigation arising in the normal course of business. There can be no assurance that such matters will be resolved in the Company's favour because the outcome of these matters is uncertain. The Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these and other matters or any amount that it may be required to pay by reason thereof would have a material impact on its financial position, results of operations or cash flows.

Disclosures concerning the Company's significant commitments can be found in Note 21 to the Interim Condensed Consolidated Financial Statements. The Company has no off-balance sheet arrangements.

Risk management contracts

The Company has entered into derivative financial instruments to reduce the exposure to unfavourable movements in commodity prices. The Company has established a system of internal controls to minimize risks associated with its derivative program and does not intend to use derivative financial instruments for speculative purposes.

Disclosures concerning the Company's risk management contracts can be found in Note 24 to the Interim Condensed Consolidated Financial Statements.

7 Related-Party Transactions

According to IFRS, parties are considered to be related if one party has the ability to "control" (financially or by share capital) the other party or have significant influence (management) on the other party in making financial, commercial, and operational decisions. The board of directors of the Company had created the New Business Opportunities Committee ("**NBOC**") to review and approve related-party transactions. The NBOC was apprised of related-party transactions prior to implementation, engaged independent legal counsel as needed, and met *in camera* to deliberate. The NBOC also reviewed the business rationale for each transaction and ensures that they are in compliance with applicable securities laws and the Company's debt covenants.

Prior to the implementation of the Restructuring Transaction, the NBOC was comprised of the following independent directors: Hernan Martinez (Chair), Dennis Mills, Monica De Greiff and Francisco Solé. The independent directors noted above are no longer directors of the Company, and as of the date hereof, the board of directors of the Company has not yet determined whether the NBOC will be reconstituted.

The Company's internal audit and legal compliance departments also monitor related-party transactions. The audit and legal compliance teams work together to compose a list of potential related parties. This list is cross-referenced against the Company's list of suppliers and other creditors.

The related-party transactions during the current quarter corresponded to the normal course of operations and were measured at fair value, which is the amount of consideration established and agreed to by the related parties and that, in the opinion of management and the NBOC, was considered similar to those negotiable with third parties.

The following sets out the details of the Company's related-party transactions. As a result of the Restructuring Transaction, there have been a number of executive and director departures since November 2, 2016. Accordingly, certain transactions disclosed below ceased to be with related parties as of that date.

a) In October 2012, the Company and Ecopetrol signed two Build, Own, Manage, and Transfer ("**BOMT**") agreements with Consorcio Genser Power-Proelectrica and its subsidiaries ("**Genser-Proelectrica**") to acquire certain power generation assets for the Rubiales field.

   Genser-Proelectrica is a joint venture between Proelectrica, in which the Company has a 21.1% indirect interest and Genser Power Inc. ("**Genser**") which is 51% owned by Interamerican Energia Corp ("**Interamerican**" formerly Pacific Power Generation Corp). On March 1, 2013, these contracts were assigned to TermoMorichal SAS ("**TermoMorichal**"), the company created to perform the agreements, in which Interamerican has a 51% indirect interest. Total commitment under the BOMT agreements is $229.7 million over ten years. In April 2013, the Company and Ecopetrol entered into another agreement with Genser-Proelectrica to acquire additional assets for a total commitment of $57 million over ten years. At the end of the Rubiales Association Contract on June 30, 2016, the Company's obligations along with the power generation assets were transferred to Ecopetrol. As at September 30, 2016, the Company did not have any advance Genser-Proelectrica (December 2015: $3.3 million).

   The Company had accounts payable of $2.2 million (December 2015: $3.6 million) due to Genser-Proelectrica as at September 30, 2016. In addition, on May 5, 2014, a subsidiary of the Company provided a guarantee in favour of XM Compañia de Expertos en Mercados S.A. on behalf of Proelectrica, guaranteeing obligations pursuant to an energy supply agreement in the aggregate amount of approximately $16.7 million. In December 2014, the Company entered into a new contract with Genser related to the operation and maintenance of the power generation facility located in the Sabanero field.

   In October 2013, the Company entered into connection agreements and energy supply agreements with Proelectrica for the supply of power to the oil fields in the Llanos basin. The connection agreements authorize Meta Petroleum Corp. and Agro Cascada S.A.S. to use the connection assets of Petroelectrica for power supply at the Quifa and Rubiales fields. The agreement commenced on November 1, 2013, and will operate for 13 years. During the three and nine months ended September 30, 2016, the Company made payments of $1.8 million and $17.1 million, respectively (2015: $10.3 million and $36.9 million), under this agreement.

The Company has entered into several take-or-pay agreements as well as interruptible gas sales and transport agreements to supply gas from the La Creciente natural gas field to Proelectrica's gas-fired plant. During the three and nine months ended September 30, 2016, the Company recorded revenues of $0.6 million and $8.3 million, respectively (2015: $2.2 million and $3.5 million), from such agreements. As at September 30, 2016, the Company had trade accounts receivable of $0.2 million (December 2015: $12.3 million) from Proelectrica.

Under the energy supply agreements, Proelectrica provides electricity to the Company for power supply at the Quifa and Rubiales fields, with payments to be calculated monthly on a demand-and-deliver basis. The term of the agreement is until December 31, 2026. The aggregate estimated energy supply agreement is for 1.5 million kilowatts.

b) Blue Pacific Assets Corp. ("**Blue Pacific**") owns a 5% interest in Proelectrica. The Company and Blue Pacific's indirect interests are held through Interamerican. Revenue from Proelectrica in the normal course of the Company's business was $0.6 million and $8.3 million for the three and nine months ended September 30, 2016 (2015: $2.2 million and $3.5 million). Three former directors (Serafino Iacono, Miguel de la Campa, and Jose Francisco Arata) and an officer (Laureano Von Siegmund) of the Company, control or provide investment advice to the holders of approximately 88% of shares of Blue Pacific.

c) As at September 30, 2016, loans receivable from related parties in the aggregate amount of $0.2 million (December 31, 2015: $0.5 million) are due from one former executive director (Serafino Iacono) and four officers (Carlos Perez, Luis Andres Rojas, Francisco Bustillos, and Jairo Lugo) of the Company. The loans are non-interest bearing and payable in equal monthly payments over a 48-month term.

In August 2015, the Company agreed to pay $8.3 million in severance to one of its officers, who retired from the Company effective August 14, 2015, which included $5.5 million in cash paid during 2015, $1.4 million paid in the three months ended March 31, 2016 and $1.4 million payable as at September 30, 2016. In addition, the departing officer's DSU entitlement was paid in kind with the Company's shares held in treasury on a one-to-one basis for a total of approximately 1.3 million common shares (on a pre-consolidation basis). Also during 2015, the Company made payments in kind of approximately 0.5 million common shares (on a pre-consolidation basis) to three departing directors as settlement for DSU entitlements.

d) The Company has take-or-pay contracts with ODL for the transportation of crude oil from the Company's fields to Colombia's oil transportation system for a total commitment of $189 million from 2016 to 2020. During the three and nine months ended September 30, 2016, the Company paid $23.8 million and $75.2 million, respectively, to ODL (2015: $27.3 million and $81.5 million) for crude oil transport services under the pipeline take-or-pay agreement, and had accounts payable of $1.6 million (December 31, 2015: $13.1 million). In addition, the Company received $0.1 million and $0.3 million from ODL during the three and nine months ended September 30, 2016 (2015: $0.7 million and $1.7 million), with respect to certain administrative services and rental equipment and machinery. The Company did not have any accounts receivable from ODL as at September 30, 2016 of $Nil (December 31, 2015: $0.1 million). The Company has an approximately 22% indirect interest in ODL.

e) The Company has ship-or-pay contracts with Bicentenario for the transportation of crude oil from the Company's fields to Colombia's oil transportation system for a total commitment of $1.2 billion from 2016 to 2025. The Bicentenario pipeline has experienced periodic suspensions following security-related disruptions. During the three and nine months ended September 30, 2016, the Company paid $50.1 million and $129.5 million, respectively, to Oleoducto Bicentenario de Colombia S.A.S. (2015: $41.5 million and $128.4 million), a pipeline company in which the Company has a 43% interest, for crude oil transport services under the pipeline ship-or-pay agreement. During the three and nine months ended September 30, 2015, the Company recognized $0.3 million and $1.3 million, respectively, in interest income from Bicentenario on a shareholder loan that has since been repaid. The Company has an advance of $87.9 million as at September 30, 2016 (December 31, 2015: $87.9 million) to Bicentenario as a prepayment of transport tariff, which is to be amortized against future barrels transported above the Company's contract capacity (Note 16). As at September 30, 2016, the Company had trade accounts receivable of $13.5 million (December 31, 2015: $0.4 million) from Bicentenario.

f) The Company has established two charitable foundations in Colombia: the Pacific Rubiales Foundation and the Foundation for Social Development of Energy Available ("**FUDES**"). Both foundations have the objective of advancing social and community development projects in the country. During the three and nine months ended September 30, 2016, the Company contributed $2.0 million and $7.3 million, respectively, to these foundations (2015: $4.3 million and $11 million). At as September 30, 2016, the Company had accounts receivable (advances) of $0.7 million (December 31, 2015: $0.4 million) and accounts payable of $1.7 million (December 31, 2015: $3.2 million). Three of the Company's former directors (Ronald Pantin, Serafino Iacono, and Miguel de la Campa) and an officer of the Company (Federico Restrepo) sit on the board of directors of the Pacific Rubiales Foundation.

g) As at September 30, 2016, the Company had demand loans receivable from Pacific Infrastructure Ventures Inc. ("**PII**") in the amount of $72.4 million (December 31, 2015: $72.4 million). The loans are guaranteed by PII's pipeline project and bear interest that ranges from LIBOR + 2% to 7% per annum. The Company owns 41.77% of PII (December 31, 2015: 41.79%). Interest income of $4.8 million and $7.4 million was recognized during the three and nine month periods ended September 30, 2016 (2015: $1.3 million and $3.7 million) regarding the loan. In addition, during the three and nine month periods ended September 30, 2016, the Company received $0.1 million and $2.7 million (2015: $3 million and $3.3 million) from PII with respect to contract fees for advisory services and technical assistance in pipeline construction of "Oleoducto del Caribe." In addition, as at September 30, 2016, the Company had accounts receivable of $2.5 million (December 31, 2015: $0.5 million) from a branch of PII.
As at September 30, 2016, the Company had accounts payable of $1.6 million to PII (December 31, 2015: $0.5 million). In December 2012, the Company entered into a take-or-pay agreement with Sociedad Puerto Bahia S.A., a company that is wholly owned by PII.
Pursuant to the terms of the agreement, Sociedad Puerto Bahia S.A. will provide for the storage, transfer, loading, and unloading of hydrocarbons at its port facilities. The contract term commenced in 2014 and will continue for seven years, renewable in one-year increments thereafter. These agreements may indirectly benefit Blue Pacific and other unrelated minority shareholders of PII.

h) In October 2012, the Company entered into an agreement with CRC, Blue Advanced Colloidal Fuels Corp. ("**Blue ACF**"), Alpha Ventures Finance Inc. ("**AVF**"), and an unrelated party whereby the Company acquired from CRC the right to a 5% equity interest in Blue ACF for a cash consideration of $5 million. Blue ACF is a company engaged in developing colloidal fuels, and its majority shareholder is AVF, which is controlled by Blue Pacific. As part of the purchase, CRC also gave to the Company the right to acquire up to an additional 5% equity interest in Blue ACF for an additional investment of up to $5 million. As of September 30, 2016, the Company had a 9.63% direct equity interest in CRC (9.84% indirect equity interest in CRC through its 21.1% ownership of Pacific Power, which in turn has a 46.67% equity interest in CRC). A former director of the Company is the executive chairman of CRC.

i) On February 29, 2016, the Company agreed to provide CGX Energy Inc. ("**CGX**") with a bridge loan of up to $2 million at an interest rate of 5% per annum, and payable within 12 months of the first draw down. As at September 30, 2016, the amount CGX had drawn down from the bridge loan was $2 million, and the Company considers this loan to be fully impaired.

In October 2014, the Company extended a bridge loan to CGX of C$7.5 million with an interest rate of 5%; as at September 30, 2016 the full amount is still outstanding and fully impaired. In November 2015, CGX issued convertible debentures to the Company in an amount of $1.5 million with a conversion price of C$0.335; as at September 30, 2016 the Company has not converted the debentures.

j) During the three and nine months ended September 30, 2016, the Company received cash of $7.2 million and $30.1 million respectively in accordance with its joint operations associated with its 49% interest in Block Z-1 in Peru. Alfa SAB de CV ("**Alfa**") owns the other 51% working capital interest in Block Z-1 and also holds 18.95% of the issued and outstanding capital of the Company (prior to the implementation of Restructuring Transaction).

k) As at September 30, 2016, the Company had accounts payable of $1.9 million (December 31, 2015: $1.9 million) outstanding to Pacific Green with respect to contributions made previously by Pacific Green to Promotora Agricola, an agricultural project associated with the Company's operations in the Llanos Basin. Pacific Green's contributions to the project are expected to be capitalized in the near term. Two former directors (Serafino Iacono and Miguel de la Campa) and two officers of the Company (Laureano von Siegmund and Federico Restrepo) have an interest in Pacific Green.

l) On December 11, 2015, the Company and the other shareholders of Interamerican, including Proenergy Corp. (a subsidiary of Blue Pacific), entered into a share purchase agreement with Faustia Development S.A., Tusca Equities Inc., and Associated Ventures Corp. (the "**Interamerican Purchasers**"), for the sale of 70% of the shares of Interamerican. As part of the transaction, the Company agreed to sell 4% of the Company's 24.9% equity interest in Interamerican to the Interamerican Purchasers for approximately $5.0 million. As a result of the sale, the Company currently owns 21.09%, and Proenergy Corp. (Blue Pacific) currently owns approximately 5% of Interamerican. Associated Ventures Corp. is controlled by Alejandro Betancourt, a director of the Company until April 26, 2016.

8 Selected Quarterly Information

	2016			2015				2014		
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Financials:										
Net sales	$ 308,705	$ 376,403	$ 456,831	$ 651,970	$ 669,995	$ 702,733	$ 799,848	$ 991,508	$ 1,330,395	$ 1,344,666
Net (loss) earnings attributable to equity holders of the parent for the period	(557,068)	(118,654)	(900,949)	(3,895,908)	(617,318)	(226,377)	(722,256)	(1,660,876)	3,484	228,527
(Loss) Earnings per share										
- basic	(176.84)	(37.67)	(286.00)	(1,236.71)	(197.07)	(72.27)	(230.56)	(526.45)	1.10	72.44
- diluted	(176.84)	(37.67)	(286.00)	(1,236.71)	(197.07)	(72.27)	(230.56)	(526.45)	1.10	72.44

9 Accounting Policies, Critical Judgments, and Estimates

Basis of Presentation

The Interim Condensed Consolidated Financial Statements for the three and nine months ended September 30, 2016 have been prepared in accordance with IAS 34 Interim Financial Reporting.

Prior to April 27, 2016, the Company was in default under its senior unsecured notes and credit facilities and had breached minimum credit rating covenants in respect of certain operational agreements for which waivers were granted. Although the Company obtained the Initial Order to commence the Restructuring Transaction on April 27, 2016 (Section 1 "Restructuring Transaction"), as of September 30, 2016 there was no guarantee with respect to the Company's ability to successfully implement the Restructuring Transaction. As a result of the default, the covenant breaches, and the persistent low oil price conditions, as at September 30, 2016, there existed material uncertainty with respect to the Company's ability to continue as a going concern. On November 2, 2016, upon the successful implementation of the Restructuring Transaction, the majority of the conditions which had cast doubt on the Company's ability to continue as a going concern no longer existed.

The Interim Condensed Consolidated Financial Statements were prepared on a going concern basis that contemplated the realization of assets and the settlement of liabilities in the normal course of business as they become due, except for the revaluation to fair value of certain financial assets and financial liabilities in accordance with the Company's accounting policies.

New Standards, Interpretations, and Amendments Adopted by the Company

The accounting policies adopted in the preparation of the Interim Condensed Consolidated Financial Statements are consistent with those followed in the preparation of the Company's Annual Consolidated Financial Statements for the year ended December 31, 2015. This is with exception for the adoption of new standards and interpretations effective as of January 1, 2016, which have or may reasonably have an impact on the Company as described below.

Amendments to IFRS 11 Joint Arrangements: Accounting for Acquisitions of Interests

The amendments to IFRS 11 require that a joint operator accounting for the acquisition of an interest in a joint operation, in which the activity of the joint operation constitutes a business, must apply the relevant IFRS 3 Business Combinations principles for business combination accounting. The amendments also clarify that a previously held interest in a joint operation is not remeasured on the acquisition of an additional interest in the same joint operation if joint control is retained. In addition, a scope exclusion has been added to IFRS 11 to specify that the amendments do not apply when the parties sharing joint control, including the reporting entity, are under common control of the same ultimate controlling party. The amendments apply to both the acquisition of the initial interest in a joint operation, and the acquisition of any additional interests in the same joint operation and are prospectively effective for annual periods beginning on or after January 1, 2016, with early adoption permitted. These amendments do not have any impact on the Company, as there has been no interest acquired in a joint operation during the period.

IAS 34 Interim Financial Reporting

The amendment clarifies that the required interim disclosures must be either in the interim condensed financial statements, or incorporated by cross-reference between the interim financial statements, and wherever they are included within the interim financial report.

The other information within the interim condensed financial statements must be available to users on the same terms as the interim condensed financial statements and at the same time. The amendment must be applied retrospectively and did not have any impact on the Company.

Standards Issued but Not yet Effective

IFRS 9 Financial Instruments

Classification and measurement of financial assets

All financial assets are measured at fair value on initial recognition, and adjusted for transaction costs if the instrument is not accounted for at fair value through profit or loss ("**FVTPL**"). Debt instruments are subsequently measured at FVTPL, amortised cost, or fair value through other comprehensive income ("**FVOCI**"), on the basis of their contractual cash flows and the business model under which the debt instruments are held. There is a fair value option ("**FVO**") that allows financial assets on initial recognition to be designated as FVTPL if that eliminates or significantly reduces an accounting mismatch. Equity instruments are generally measured at FVTPL. However, entities have an irrevocable option on an instrument-by-instrument basis to present changes in the fair value of non-trading instruments in other comprehensive income ("**OCI**") without subsequent reclassification to profit or loss.

Classification and measurement of financial liabilities

For financial liabilities designated as FVTPL using the FVO, the amount of change in the fair value of such financial liabilities that is attributable to changes in credit risk must be presented in OCI. The remainder of the change in fair value is presented in profit or loss, unless presentation in OCI of the fair value change in respect of the liability's credit risk would create or enlarge an accounting mismatch in profit or loss. All other IAS 39 Financial Instruments: Recognition and Measurement classification and measurement requirements for financial liabilities have been carried forward into IFRS 9, including the embedded derivative separation rules and the criteria for using the FVO.

Impairment

The impairment requirements are based on an expected credit loss ("**ECL**") model that replaces the IAS 39 incurred loss model. The ECL model applies to debt instruments accounted for at amortised cost or at FVOCI, most loan commitments, financial guarantee contracts, contract assets under IFRS 15 Revenue from Contracts with Customers, and lease receivables under IAS 17 Leases. Entities are generally required to recognise 12-month ECL on initial recognition (or when the commitment or guarantee was entered into), and thereafter as long as there is no significant deterioration in credit risk.

However, if there has been a significant increase in credit risk on an individual or collective basis, then entities are required to recognise lifetime ECL. For trade receivables, a simplified approach may be applied whereby the lifetime ECL are always recognised.

The Company previously adopted IFRS 9 (2013) and plans to adopt the amendments to IFRS 9 (2014) at the effective date, and is in the process of assessing the impact on its consolidated financial statements. The amendments are effective for annual periods beginning on or after January 1, 2018.

Early application is permitted for reporting periods beginning after the issue of IFRS 9 on July 24, 2014 by applying all of the requirements in this standard at the same time. Alternatively, entities may elect to early apply only the requirements for the presentation of gains and losses on financial liabilities designated as FVTPL without applying the other requirements in the standard.

IFRS 15 Revenue from Contracts with Customer

IFRS 15 replaces all existing revenue requirements in IFRS (IAS 11 Construction Contracts, IAS 18 Revenue, IFRIC 13 Customer Loyalty Programmes, IFRIC 15 Agreements for the Construction of Real Estate, IFRIC 18 Transfers of Assets from Customers, and SIC 31 Revenue – Barter Transactions Involving Advertising Services), and applies to all revenue arising from contracts with customers, unless the contracts are in the scope of other standards, such as IAS 17. Its requirements also provide a model for the recognition and measurement of gains and losses on disposal of certain non-financial assets, including property, equipment, and intangible assets. The standard outlines the principles an entity must apply to measure and recognize revenue. The core principle is that an entity will recognize revenue at an amount that reflects the consideration to which the entity expects to be entitled in exchange for transferring goods or services to a customer.

The principles in IFRS 15 will be applied using a five-step model:

1. Identify the contract(s) with a customer
2. Identify the performance obligations in the contract
3. Determine the transaction price
4. Allocate the transaction price to the performance obligations in the contract
5. Recognise revenue when (or as) the entity satisfies a performance obligation

The standard requires entities to exercise judgement, taking into consideration all of the relevant facts and circumstances when applying each step of the model to contracts with their customers. The standard also specifies how to account for the incremental costs of obtaining a contract, and the costs directly related to fulfilling a contract. Application guidance is provided in IFRS 15 to assist entities in applying its requirements to certain common arrangements, including licences of intellectual property, warranties, rights of return, principal-versus-agent considerations, options for additional goods or services, and breakage. The new standard will apply for annual periods beginning on or after January 1, 2018. Entities can choose to apply the standard using either a full retrospective approach, with some limited relief provided, or a modified retrospective approach. Early application is permitted and must be disclosed.

The Company plans to adopt the new standard at the effective date and is in the process of assessing the impact on its consolidated financial statements.

IFRS 16 Leases

The scope of IFRS 16 includes leases of all assets, with certain exceptions. A lease is defined as a contract, or part of a contract, that conveys the right to use an asset (the underlying asset) for a period of time in exchange for consideration. IFRS 16 requires lessees to account for all leases under a single on-balance sheet model in a similar way to finance leases under IAS 17. The standard includes two recognition exemptions for lessees – leases of 'low-value' assets (i.e., personal computers), and short-term leases (i.e., leases with a lease term of 12 months or less). At the commencement date of a lease, a lessee will recognise a liability to make lease payments (i.e., the lease liability), and an asset representing the right to use the underlying asset during the lease term (i.e., the right-of-use asset). Lessees will be required to separately recognise the interest expense on the lease liability and the depreciation expense on the right-of-use asset.

Lessees will be required to remeasure the lease liability upon the occurrence of certain events (i.e., a change in the lease term, or a change in future lease payments resulting from a change in an index, or rate used to determine those payments). The lessee will generally recognise the amount of the remeasurement of the lease liability as an adjustment to the right-of-use asset. Lessor accounting is substantially unchanged from today's accounting under IAS 17. Lessors will continue to classify all leases using the same classification principle as in IAS 17, and distinguish between two types of leases: operating and finance leases. The new standard will apply for annual periods beginning on or after January 1, 2019. A lessee can choose to apply the standard using either a full retrospective or a modified retrospective transition approach. The standard's transition provisions permit certain reliefs. Early application is permitted, but not before an entity applies IFRS 15.

The Company plans to adopt the new standard at the effective date and is in the process of assessing the impact on its consolidated financial statements.

IAS 7 Statement of Cash Flows

The amendments to IAS 7 Statement of Cash Flows are part of the IASB's Disclosure Initiative, and require an entity to provide disclosures that enable users of financial statements to evaluate changes in liabilities arising from financing activities, including both changes arising from cash flows and non-cash changes. The amendments are effective for annual periods beginning on or after January 1, 2017, with early application permitted.

The Company plans to adopt the new standard at the effective date and is in the process of assessing the impact on its consolidated financial statements.

IAS 12 Income taxes

The IASB issued the amendments to IAS 12 Income Taxes to clarify the accounting for deferred tax assets for unrealised losses on debt instruments measured at fair value. The amendments clarify that an entity needs to consider whether tax law restricts the sources of taxable profits against which it may make deductions on the reversal of that deductible temporary difference. Furthermore, the amendments provide guidance on how an entity should determine future taxable profits, and explains in which circumstances taxable profit may include the recovery of some assets for more than their carrying amount. The amendments are effective for annual periods beginning on or after January 1, 2017. Entities are required to apply the amendments retrospectively. However, on initial application of the amendments, the change in the opening equity of the earliest comparative period may be recognised in opening retained earnings (or in another component of equity, as appropriate), without allocating the change between opening retained earnings and other components of equity. Entities applying this relief must disclose that fact. Early application is permitted. If an entity applies the amendments for an earlier period, it must disclose that fact.

The Company plans to adopt the new standard at the effective date, and is in the process of assessing the impact on its consolidated financial statements.

10 Internal Control over Financial Reporting and Disclosure Controls and Procedures

In accordance with National Instrument 52-109 - Certification of Disclosure in Issuers' Annual and Interim Filings ("**NI 52-109**") of the Canadian Securities Administrators ("**CSA**"), the Company issues a "Certification of Interim Filings" quarterly. This Certification requires certifying officers to state that they are responsible for establishing and maintaining Disclosure Controls and Procedures ("**DC&P**") and Internal Control over Financial Reporting ("**ICFR**") as those terms are defined in NI 52-109.

The Company has established a continuous control testing process with an independent auditor throughout the year. The testing process adds value to our compliance program by:

- Performing process risk assessment by identifying high risk and establishing mitigation plans
- Optimizing key controls and reviewing and updating risk control matrices to all company processes
- Increasing reliance on entity-level and automated application controls
- Identifying best practices and process improvement opportunities

During the third quarter of 2016, 172 controls were tested over the 614 total optimized controls the Company has implemented. From this evaluation, the Company concluded that there are no material weaknesses or significant deficiencies in the design or effectiveness of ICFR as at September 30, 2016.

The Company's ICFR is designed to provide reasonable assurance regarding the reliability of the Company's financial reporting for external purposes in accordance with IFRS. The Company's ICFR includes:

- Maintaining records that accurately and fairly reflect our transactions
- Providing reasonable assurance that transactions are recorded as necessary for preparation of our consolidated financial statements in accordance with IFRS or other applicable and generally accepted accounting principles
- Providing reasonable assurance that receipts and expenditures are made in accordance with authorizations of management and directors of the Company
- Providing reasonable assurance that unauthorized acquisition, use, or disposition of Company assets that could have a material effect on the Company's consolidated financial statements are prevented or detected on a timely basis
- Providing reasonable assurance to access and process information in the system through a continous automated monitoring control process

The Company's ICFR may not prevent or detect all misstatements because of inherent limitations. Additionally, projections of any evaluation of effectiveness in future periods are subject to the risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with the Company's policies and procedures.

During the three months ended September 30, 2016, there was no change in the Company's ICFR that has materially affected, or is reasonably likely to materially affect, the Company's ICFR.

The Company's DC&P is designed to provide reasonable assurance that:

a) Material information relating to the Company is made known to the Company's certifying officers by others, particularly during the period in which the annual filings are being prepared
b) Information required to be disclosed by the Company in its annual filings, interim filings, and other reports filed or submitted by it under securities legislation is recorded, processed, summarized, and reported within the time periods specified in securities legislation

Based on the Company's evaluation carried out to assess the effectiveness of the Company's DC&P, the Company concluded that the DC&P were designed and operated effectively as at September 30, 2016.

11 Further Disclosures

Royalties and High-Price Participation

The current royalty rates for volumes of hydrocarbons produced from the Company's Colombian assets range from 5% to 20%. Royalties on production represent the entitlement of the respective states to a portion of the Company's share of production, and are recorded using rates in effect under the terms of existing contracts and laws applicable at the time of hydrocarbon discovery. In Colombia, royalties for oil may be payable in kind while royalties for gas are payable in cash. During the second quarter of 2014, the ANH requested the Company to pay in cash the royalties related to the condensate of La Creciente field and the crude oil of minor fields operated by the Company. In Peru, royalty calculations for oil range from 5% to 23%, which the government allows companies to pay either in kind or in cash. However, the current practice is to pay the royalties in cash.

Additional Production Share in the Quifa SW Field

The Company's share of production after royalties in the Quifa SW field is 60%. However, this participation may change monthly as a function of the PAP formula stipulated in the Quifa Association Contract. Starting in April 2014, the Company initiated the delivery of the additional PAP production from the Quifa SW field to Ecopetrol. In addition, during the second half of 2014, the Company agreed to deliver to Ecopetrol approximately 6,500 bbl/d to settle the accumulated PAP prior to the final arbitration decision (previously recorded as a financial provision in the Company's financial statements beginning at the end of 2012). During the first quarter of 2014, the Company fully delivered the remaining balance of prior period-accumulated PAP volumes.

Carrizales Field (Cravoviejo Block)

On April 27, 2014, the exploitation area of the Carrizales field reached five million barrels in accumulated production of oil, activating the ANH rights on additional PAP pursuant to the E&P Cravoviejo contract. According to the contract terms, this additional participation share from the Carrizales field is payable either in cash or in kind, and has been accounted for as part of the operating cost for this field.

PAP Disagreement with the ANH

The Company has certain exploration contracts acquired through business acquisitions where there existed outstanding disagreements with the ANH, relating to the interpretation of the high-price participation clause. These contracts require high-price participation payments to be paid to the ANH once an exploitation area within a contracted area has cumulatively produced five million or more barrels of oil. The disagreement is around whether the exploitation areas under these contracts should be determined individually or combined with other exploration areas within the same contracted area, for the purpose of determining the five million barrel threshold. The ANH has interpreted that the high-price participation should be calculated on a combined basis.

The Company disagrees with the ANH's interpretation and asserts that in accordance with the exploration contracts, the five million barrel threshold should be applied on each of the exploitation areas within a contracted area. The Company has several contracts that are subject to ANH high-price participation. One of these contracts is the Corcel Block, which was acquired as part of the Petrominerales acquisition, and is the only one for which an arbitration process has been initiated. However, the arbitration process for Corcel was under suspension at the time the Company acquired Petrominerales. As at June 30, 2016, the amount under arbitration is approximately $194 million plus related interest of $43 million. The Company also disagrees with the interest rate that the ANH has used in calculating the interest cost.

The Company asserts that since the high-price participation is denominated in the U.S. dollar, the contract requires the interest rate to be three-month LIBOR + 4%, whereas the ANH has applied the highest legally authorized interest rate on Colombian peso liabilities, which is over 20%. An amount under discussion with the ANH for another contract is approximately $99 million plus interest.

The Company and the ANH are currently in discussion to further understand the differences in interpretation of these exploration contracts. The Company believes that it has a strong position with respect to the high-price participation based on legal interpretation of the contracts and technical data available. However, in accordance with IFRS 3, to account for business acquisitions the Company is required to and has recorded a liability for such contingencies as of the date of acquisition, even though the Company believes the disagreement will be resolved in favour of the Company. The Company does not disclose the amount recognized as required by paragraphs 84 and 85 of IAS 37, on the grounds that this would be prejudicial to the outcome of the dispute resolution.

Update on Environmental Permits

During this quarter there was not any licence granted by the authorities. The company continues carrying out all the activities in compliance with the environmental regulations and procedures.

The Company is waiting for the Environmental Licence for Canaguaro Field and the Environmental Licence Modification for La Creciente field, both to be granted by the Environmental National Authority hopefully the last quarter of 2016.

12 Additional Financial Measures

This report contains the following financial terms that are not considered in IFRS: Adjusted EBITDA, Net (Loss) Earnings from Operations, and Funds Flow from Operations. These non-IFRS measures do not have any standardized meaning, and therefore are unlikely to be comparable to similar measures presented by other companies. These non-IFRS financial measures are included because management uses this information to analyze operating performance, leverage, and liquidity. Therefore, these measures should not be considered in isolation or as a substitute for measures of performance prepared in accordance with IFRS.

Adjusted EBITDA

Management believes that Adjusted EBITDA is an important indicator of the Company's ability to generate liquidity through operating cash flow to fund future working capital needs, service outstanding debt, and fund future capital expenditures. The exclusion of non-cash and one-time items eliminates the impact on the Company's liquidity and normalizes the result for comparative purposes. Other issuers may calculate Adjusted EBITDA differently.

A reconciliation of Net Earnings to Adjusted EBITDA follows:

(in thousands of US$)	Three Months Ended September 30 2016	Three Months Ended September 30 2015	Nine Months Ended September 30 2016	Nine Months Ended September 30 2015
Net loss [1]	**$ (557,068)**	**$ (617,318)**	**(1,576,671)**	**$ (1,565,951)**
Adjustments to net loss				
Income tax expense (recovery)	20,381	(34,193)	38,953	(107,845)
Foreign exchange (gain) loss	(17,541)	71,887	(22,720)	113,081
Finance cost	22,943	71,954	124,748	228,929
Loss (gain) on risk management contracts	18,514	(136,558)	125,986	(67,921)
(Gain) Loss of equity-accounted investees	(10,720)	17,692	(67,093)	(13,662)
Other expenses (income)	2,792	6,094	(41,628)	53,078
Share-based compensation	-	(8,880)	(8,503)	4,681
Equity tax	-	-	26,901	39,149
(Loss) gain attributable to non-controlling interest	(2,304)	(11,699)	10,203	(847)
Depletion, depreciation and amortization	113,802	344,577	490,285	1,148,735
Impairment and exploration expenses	423,913	568,013	1,113,599	1,016,980
Restructuring Costs	26,795	-	91,515	-
Adjusted EBITDA	**$ 41,507**	**$ 271,569**	**$ 305,575**	**$ 848,407**

1. Net loss attributable to equity holders of the parent.

Funds Flow from Operations

(in thousands of US$)	Three Months Ended September 30 2016	Three Months Ended September 30 2015	Nine Months Ended September 30 2016	Nine Months Ended September 30 2015
Cash flow from operating activities	$ (11,912)	$ (57,861)	$ (54,142)	$ 138,396
Changes in non-cash working capital	22,846	205,064	128,037	546,982
Deferred revenue net proceeds	-	50,000	75,000	(149,155)
Funds flow from operations	**$ 10,934**	**$ 197,203**	**$ 148,895**	**$ 536,223**

Net Loss from Operations

(in thousands of US$)	Three Months Ended September 30 2016	2015	Nine Months Ended September 30 2016	2015
Net loss [(1)]	**$ (557,068)**	**$ (617,318)**	**(1,576,671)**	**$ (1,565,951)**
Finance costs	22,943	71,954	124,748	228,929
(Gain) loss of equity-accounted investees	(10,720)	17,692	(67,093)	(13,662)
Equity tax	-	-	26,901	39,149
Foreign exchange (gain) loss	(17,541)	71,887	(22,720)	113,081
Loss (gain) on risk management contracts	18,514	(136,558)	125,986	(67,921)
Other expenses (income)	2,792	6,094	(41,628)	53,078
Income tax expense (recovery)	20,381	(34,193)	38,953	(107,845)
(Loss) gain attributable to non-controlling interest	(2,304)	(11,699)	10,203	(847)
Net loss from operations	**$ (523,003)**	**$ (632,141)**	**$ (1,381,321)**	**$ (1,321,989)**

1. Net loss attributable to equity holders of the parent.

Oil and gas metrics

This report contains metrics commonly used in the oil and natural gas industry, such as operating net backs, operating costs, and average realized price. These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies. Therefore, these terms should not be used to make comparisons. Operating net backs have been calculated by subtracting production costs, transportation costs, diluent costs, other costs, royalties, and overlift or underlift costs from the realized oil and natural gas sales price per barrel of oil equivalent, and may be used to determine the profit realized by the Company for each barrel of oil equivalent sold. Operating costs have been calculated by adding production costs, transportation costs, and diluent costs, and may be used to determine the profitability of the Company. Average realized price is calculated by dividing the average daily volume sold by the revenue received for such sales over the course of a year, and may be used to determine the average price received by the Company for each barrel of oil equivalent sold. Management uses these oil and gas metrics for its own performance measurement, and to provide stakeholders with measures to compare the Company’s operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this report, should not be relied upon for investment or other purposes.

13 Sustainability Policies

New milestones in our gender equality declaration

Aligned with its Gender Equality Declaration and the initiatives implemented by its Gender Committee, for the past two years the Company participated in the Equipares Gender Equality Seal process granted by the United Nations Development Program and the Colombian Ministry of Labor. In September 2016, the company received the Equipares Certification obtaining 98.9 out of 100 possible points, becoming the first oil and gas company in South America to receive this recognition. The award ceremony will take place in November in Panama City.

Update on our Peruvian operations

After the Peruvian State assigned block 135 to the Company, in 2010 the government approved the Matses territory expansion, which encompasses more than nine thousand hectares of the block. This is a small portion of the total area, reiterating that the Government could very well put the rights of the people or the country before companies, and still allow them to maintain operational feasibility in areas that we are interested in operating with no impact to the Matses territory. Regardless of the former, Block 135 is currently in force majeure and no planned activities are being executed.

Update on the Constitutional Court decision

As reported in the last quarter, the Company proceeded to compensate activities in line with the Constitutional Court’s mandate for the Vencedor Pirirí Prior Consultation Process in the Quifa Block. To date it has executed one third of the proposed budget in a cattle productive project that will further advance the regional agricultural vocation and improve the social and economic situation of these indigenous communities.

Contributing to social development in Colombia

Before our intervention, the water system within the Rubiales rural settlement in Puerto Gaitan, Meta, worked with a septic tank. With the help of local government, the septic tanks turned into power plants powered with diesel fuel, operating 9 hours a day. Aside from involving a cost to the community who had to pay for the fuel, the burning of diesel is highly polluting. Aware of the difficulties associated with establishing electrical networks in marginalized areas of the country, the company focused on solving the problem through solar energy, traditionally reserved to communities with higher incomes. This project consists on a pipeline operated through a photovoltaic solution. Its implementation increased access to clean water and extended hour coverage, reduced operating costs of the plant, halted emissions to zero, and improved the health conditions of the inhabitants of the Rubiales rural settlement and by extension their quality of life.

This project has benefit 536 people within Quifa’s field influence area, improving their situation and showing the community how both parties can work together to coexist in harmony.

Sustainability reporting

Finally, in the month of July 2016, the Company published its seventh sustainability report in accordance with the comprehensive option of the Global Reporting Initiative guideline and external assurance by Deloitte, helping creditors, analysts, and our stakeholders in general understand the areas of opportunity and impact, and the Company’s approach to both challenges.

14 Risks and Uncertainties

The business, operations, and earnings of the Company could be impacted by the occurrence of risks and uncertainties of all kinds, including financial, operational, technological, regulatory, and political risks, that might affect the oil and gas industry generally, or the Company specifically.

As mentioned above, on April 27, 2016 the Company obtained an Initial Order from the Court under the CCAA, which (i) authorized the Filing Entities to commence a Court-supervised restructuring proceeding; and (ii) provided protections to allow normal operations to continue as the Filing Entities proceed to consummate the Restructuring Transaction. The Company emerged from the CCAA proceedings (the "**CCAA Emergence**"), and the Restructuring Transaction was completed, on November 2, 2016.

As part of the Restructuring Transaction, on June 22, 2016, the Company closed the DIP Financing in the amount of $500 million, less an original issue discount, with: (i) certain holders of the Company's senior unsecured notes, and (ii) Catalyst. As explained elsewhere, upon CCAA Emergence, $250 million of the DIP Financing was converted into common shares of the Company and the remaining $250 million was converted into Exit Notes. In addition, the Company entered into a $115.5 million new letter of credit facility with certain lenders under the Company's pre-existing credit facilities.

The Company intends to fund its anticipated cash requirements through the end of 2017, primarily through cash on hand, proceeds from the DIP Financing, and cash flows from operations.

Although the Company believes that its liquidity concerns have been addressed through the completion of the Restructuring Transaction, the Company may be negatively impacted by factors related to the nature of the Restructuring Transaction itself and the CCAA filing that preceded it. For example:

- Adverse publicity related to the CCAA Proceedings may have affected the Company's business
- The Restructuring Transaction may not improve the Company's business
- The common shares may be concentrated in a few holders with additional rights
- There may be an absence of a public market for the common shares and share prices may be depressed
- The trading price for the common shares may be volatile.

Other material risk factors related to the Company and the oil and gas industry include, but are not limited to:

- Volatility in market prices for oil and natural gas
- A continued depressed oil and natural gas price environment with the potential of further decline
- The Company's ongoing cost and capital expenditure reduction efforts may be ineffective or have unintended consequences
- The effect of ratings downgrades on the Company's business and operations
- Uncertainties associated with estimating oil and natural gas reserves
- The expiration of the Company's exploration and exploitation contracts and the costs associated therewith
- Uncertainty over the ability to add reserves through exploration, acquisition, or development activities to mitigate the effect of reserves and production decline over time.
- The possibility that if certain contingencies occur, they could have a material adverse effect on the Company's business, results of operations, and financial condition
- The risk of fire, explosions, mechanical failure, pipe or well cement failure, well casing collapse, pressure or irregularities in formations, chemical and other spills, unauthorized access to hydrocarbons, accidental flows of oil, natural gas or well fluids, sour gas releases, contamination of oil and gas, vessel collision, structural failure, loss of buoyancy, storms, earthquakes, hurricanes, floods, or other adverse weather conditions, and other occurrences associated with the exploration and production of hydrocarbons
- The availability of drilling and related equipment, transportation, power, and technical support in the areas where the Company's activities will be conducted
- The costs associated with, and availability of funds for, abandoning and reclaiming wells, facilities, and pipelines that the Company uses for production of oil and gas reserves

- The costs of compulsory work programs under the Company's exploration contracts and the penalties associated with failing to meet them
- The impact of operating costs on net revenue
- Uncertainties relating to the availability and costs of financing needed in the future
- Delays in obtaining required environmental and other licences
- The effect of global financial conditions on the Company's operations and ability to raise capital
- Competition in the oil and gas industry for capital, acquisitions of reserves, undeveloped lands, and skilled personnel, among other things
- The ability to attract and retain qualified personnel
- An inability to manage growth
- Disruptions in, or the increase of costs associated with, the transportation of hydrocarbons
- The direct and indirect costs associated with labour disruptions in or around the Company's operations
- Over-reliance on a small number of customers and associated failures to collect receivables from customers in a timely manner or at all
- The nature of the Company's business exposes it to litigation relating to labour, health and safety matters, environmental matters, regulatory, tax, and administrative proceedings, governmental investigations, arbitration, and contractual claims and disputes, the results of which are difficult to predict
- The effect and costs of environmental regulation in the countries in which the Company operates
- The acquisition of title to oil and natural gas properties in the jurisdictions in which the Company operates is a detailed and time-consuming process and is often not capable of conclusive determination
- Fluctuations in foreign exchange or interest rates and stock market volatility
- The possibility of disproportionate effects and costs associated with the concentration of a majority of the Company's producing properties and leases in the Llanos Basin in eastern Colombia
- The effects of actual or perceived ethical misconduct and legal or regulatory non-compliance
- It may be difficult or impossible to enforce judgments granted by a court in Canada against the assets of the Company or the directors and officers of the Company residing outside of Canada
- There can be no assurance that restrictions on repatriation of earnings from Colombian subsidiaries will not be imposed in the future
- The Company may be unable to declare and pay dividends on its common shares;
- If the Company is unable to maintain the efficacy of its technology, its ability to manage its business and to compete may be impaired
- The Company's ability to successfully bid on and acquire additional properties, to discover reserves, to participate in drilling opportunities, and to identify and enter into commercial arrangements is dependent on developing and maintaining effective working relationships with industry participants
- The Company's equity interest in Pacific Infrastructure may be diluted
- The success of the Company's management in integrating the operations, technologies, and personnel of any acquired companies

In addition, the Company faces risks related to its operations in Colombia and the Company's other markets that include, but are not limited to, those associated with:

- Economic and political developments in Colombia, Guatemala, Peru, Brazil, Guyana, and Belize
- The effect of the rate of Colombian economic growth on the operations of the Company
- The effect of guerrilla activity in South America
- The Company's operations may be adversely affected by security incidents that are not within the control of the Company, including, among other things, kidnappings, extortion ,or criminal activity
- The jurisdictions in which the Company operates possibly having different or less developed legal systems than Canada or the United States
- The oil and gas industry in Colombia and the rest of the countries where the Company operates not being as efficient or developed as the oil and gas industry in the United States or Canada
- The possibility that the countries in which the Company operates may impose exchange controls, thereby limiting funding of exploration and operations, or creating adverse tax consequences associated with such funding
- The extensive controls and regulations imposed by various levels of government on the oil and natural gas industry in Colombia and the other countries where the Company operates

- The possibility that in the countries where the Company operates or has investments, the state can exercise eminent domain or expropriation powers in respect of the Company's assets

The Company's Annual Information Form and the Company's Information Circular and Proxy Statement dated July 8, 2016, prepared in connection with the Restructuring Transaction, each available at www.sedar.com, contain a complete discussion of the risks and uncertainties that could have an effect on the business and operations of the Company. Readers are urged to read such discussion in its entirety.

15 Advisories

Boe conversion

The term “boe” is used in this MD&A. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of cubic feet to barrels is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In this MD&A, boe has been expressed using the Colombian conversion standard of 5.7 Mcf: 1 bbl required by the Colombian Ministry of Mines and Energy.

All of the Company’s natural gas reserves are contained in the La Creciente, Guama, and other blocks in Colombia, as well as in the Piedra Redonda field in Block Z-1 in Peru. For all natural gas reserves in Colombia, boes have been expressed using the Colombian conversion standard of 5.7 Mcf: 1 bbl required by the Colombian Ministry of Mines and Energy. For all natural gas reserves in Peru, boes have been expressed using the Canadian conversion standard of 6.0 Mcf: 1 bbl. If a conversion standard of 6.0 Mcf: 1 bbl were used for all the Company’s natural gas reserves, this would result in a reduction in the Company’s net 1P and 2P reserves of approximately 4.2 and 4.7 MMboe respectively.

16 Abbreviations

The following abbreviations are frequently used in our MD&A.

1P	Proved reserves (also known as P90)
2P	Proved reserves + Probable reserves.
3P	Proved reserves + Probable reserves + Possible reserves
API	American Petroleum Institute - gravity measure of petroleum liquid
bbl	Barrels
bbl/d	Barrels per day
Bcf	Billion cubic feet
boe	Barrels of oil equivalent
boe/d	Barrels of oil equivalent per day
BSW	Basic sediments and water
Btu	British thermal units
Bwd	Barrels of water per day
CBM	Cubic billion metre
DWT	Dead weight tonnage
EPC	Engineering, procurement and construction
ESP	Electro-Submersible Pump
FOB	Free on board
GOR	Gas – Oil Ratio
GDP	Gross Domestic Product
ha	Hectare
km	Kilometres
KWh	Kilowatt Hour
Mbbl	Thousand barrels
Mbbl/d	Thousand barrels per day
Mboe	Thousand barrels of oil equivalent
Mboe/d	Thousand barrels of oil equivalent per day
MDRT	Measure depth rotary table
MDT	Modular formation dynamics test
MWD	Measurement while drilling
MMcf/d	Million cubic feet per day
MD	Measured depth
MMbbl	Million barrels
MMbbl/d	Million barrels of oil per day
MMboe	Million barrels of oil equivalent
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMcf/d	Million cubic feet per day
MMscf/d	Million standard cubic feet per day
MW	Megawatts
MWh	Megawatts per hour
NGL	Natural gas liquids
Scf	Standard cubic feet
Stb/d	Standard barrels per day
Tcf	Trillion cubic feet
TD	Total depth
TVDSS	True vertical depth below sea level
USGC	US Gulf Coast
WTI	West Texas Intermediate index