PACIFIC E&P

MANAGEMENT DISCUSSION & ANALYSIS

August 12, 2016
For the three months ended June 30, 2016

CONTENTS

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 Annual Information Form, dated March 18, 2016, 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 June 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 June 30, 2016 and June 30, 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 15.

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, on SIMEV at www.superfinanciera.gov.co/web_valores/Simev, 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.

This MD&A was prepared originally in the English language and subsequently translated into Spanish. In the case of differences or discrepancies between the original and translated version, the English document shall prevail and be treated as the governing version.

1 Corporate Restructuring Transaction

In the second half of 2015, the Company started to review and consider various strategic alternatives, including potential investment and divestment opportunities. At the end of the third quarter and into the fourth quarter of 2015, the Company realized that it would be in violation of its covenants under its credit facilities to maintain consolidated net worth above U.S.$1 billion and it therefore needed to obtain a waiver from its bank lenders to avoid a default thereunder, which waiver was granted on September 29, 2015t. However, as oil prices continued to deteriorate in the middle of the fourth quarter, the Company appointed a financial advisor (Lazard Freres & Co. LLC) to provide restructuring advice and assist in negotiations with a lender steering committee representing the syndicate of lenders holding the $1.0 billion revolving credit facility and to aid in the Company's consideration and execution of potential strategic alternatives.

In mid-January 2016, the Company elected to use the 30-day grace period with respect to upcoming interest payments on certain of its unsecured senior notes in order to engage with its creditors (noteholders and banks) with a view of making its capital structure more suitable to current market conditions. As oil prices continued to deteriorate throughout January and February, it became clear that the best solution was to undergo a full corporate debt-restructuring to best preserve the assets of the Company. Also in mid-January, the Board of Directors formed the Independent Committee to assist the full Board of Directors in analyzing strategic alternatives in respect of the Company's capital structure.

In late February, the Company commenced a formal solicitation process to solicit interest from prospective investors with respect to an acquisition of substantially all or a portion of the Company's assets or an investment to support a recapitalization of the Company.

After an extensive competitive bid solicitation process involving, the distribution of letters to approximately 60 potentially interested parties and the submission of six bids and direct negotiations among the bidders, an ad hoc committee comprised of holders of the Company's senior unsecured notes (the "**Ad Hoc Committee**"), and certain of the Company's lenders under its credit facilities (the "**Supporting Bank Lenders**"), the Board of Directors, acting on a recommendation from the Independent Committee, approved a comprehensive restructuring transaction (the "**Restructuring Transaction**") with: (i) The Catalyst Capital Group Inc. on behalf of investment funds managed by it ("**Catalyst**"); (ii) cetain holders of the Company's seniour unsecured notes (including certain members of an the Ad Hoc Committee); and (iii) certain of the Company's lenders unders its credit facilities. In carrying out its review and recommendation, the Independent Committee retained UBS Securities Canada Inc. as the independent financial advisor and Osler, Hoskin & Harcourt LLP as the independent legal counsel.

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 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 previously announced.

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. (collectively, the "**Colombian Filers**") filed a request for recognition in Colombian 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 obtained from the Court, on April 27, 2016, pursuant to the CCAA. 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.

The Restructuring Transaction

The Restructuring Transaction is a comprehensive financial restructuring of certain financial obligations of the Pacific that will significantly reduce debt, improve liquidity and best position the Company to navigate the current oil price environment. The Restructuring Transaction represents the culmination of a thorough solicitation process with consensual and direct negotiations among the Company, the Ad Hoc Committee, the Supporting Bank Lenders and each of the bidders, including Catalyst.

During the Restructuring Transaction, operations of the Company's subsidiaries (the "**Pacific Group**") continue as normal and without disruption. All obligations to the Pacific Group's suppliers, trade partners and contractors continue to be met throughout this process.

The Company's bank indebtedness and indebtedness with regard to its senior unsecured notes will be restructured as set out below:

- Implementation by way of a plan of arrangement pursuant to a court-supervised CCAA process in Canada, together with appropriate proceedings in Colombia under Law 1116, and in the United States.
- Certain of the Company's noteholders (the "**Funding Creditors**") and Catalyst have jointly provided $500 million of debtor-in-possession financing (the "**DIP Financing**") less an original issue discount. The DIP Financing is secured by a superpriority lien over the assets of the Company and 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 has 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 have provided U.S.$240 million for the purchase of notes and warrants (after taking into account the original issue discount) pursuant to the DIP Offering (the "**Creditor DIP Financing**").
- The Funding Creditors purchased warrants, with a nominal exercise price, to acquire their pro-rata share of 12.5% of the fully diluted common shares of the reorganized Company on implementation of the Restructuring Transaction. The Creditor DIP Financing will not be repaid upon the Company's exit under the Restructuring Transaction but instead will be amended and restated as five-year secured notes (the "**Exit Notes**"). The Exit Notes will 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 U.S.$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 Plan Sponsor DIP Financing will be exchanged for approximately 29.3% of the fully diluted common shares of the reorganized Company.
- The claims by the Company's creditors (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), will be settled in exchanged for approximately 58.2% of the common shares of the reorganized Company (which is payable 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**"). This 2.2% of the reorganized Company will be payable 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 will have 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 common shares of the Company will be 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 will be rounded down to the nearest whole number without consideration in respect thereof.
- The Restructuring Transaction will be subject to certain conditions, including creditor and court approval, which is being sought as part of the court-supervised restructuring process.

- On completion of the Restructuring Transaction, it is contemplated that the fully diluted common shares in the reorganized Company, not giving effect to: (i) any of the Affected Creditors exercising or utilizing the Cash Out Offer; or (ii) any distribution of the Supporting Noteholder Consideration (as described below), will be allocated as follows:

Catalyst (including as a provider of the DIP Financing)	29.3%
Funding Creditors	12.5%
Affected Creditors	58.2%

- The Restructuring Transaction will result in a net reduction of the Company's indebtedness of approximately $5 billion and a net reduction of annual interest expense by approximately $258 million. Following the conclusion of the Restructuring Transaction, the $250 million of new secured notes will be the only long term debt in the Company's capital structure outside of facilities to support letters of credit or hedging activities.
- The Company's operations will continue as normal and without disruption.

On May 3, 2016, the Colombian Superintendence of Corporations (the "**Superintendence**") increased the level of supervision and monitoring over the Colombian branches of Meta Petroleum Corp., Pacific Stratus Energy Colombia Corp., Petrominerales Colombia Corp. and Grupo C&C Energia (Barbados) Ltd. (collectively, the "**Colombian Branches**") by formally assuming "control" over such branches pursuant to a resolution issued by the Superintendence under file 36241 (the "**Resolution**").

On July 13, 2016, the Company filed its meeting materials in connection with its meeting (the "**Creditors' Meeting**") of certain Affected Creditors being held on August 17, 2016 on SEDAR (Canada) and SIMEV (Colombia), including an information circular and proxy statement dated July 8, 2016 (the "**Circular**"). The Company has mailed meeting materials to Affected Creditors, prepared in connection with the Restructuring Transaction. The Restructuring Transaction has support from supporting creditors (who have, subject to certain terms and conditions, agreed to vote in favour of the Restructuring Transaction) holding approximately 79% of the aggregate affected claims of the Company's noteholders and lenders under the Company's credit facilities.

On June 22, 2016, the Company closed a debtor-in-possession financing (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. 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.

2 Highlights for the Second Quarter of 2016

Financial and Operating Summary

(in thousands of US$ except per share amounts or as noted)	Q2 2016	Q1 2016	Q2 2015
Operating activities			
Average sales volumes (boe/d)	**110,024**	120,567	143,225
Average oil and gas sales (boe/d)	**109,736**	120,220	132,417
Average trading sales (bbl/d)	**288**	347	10,808
Average net production (boe/d)	**127,951**	142,337	152,428
Average net production oil (bbl/d)	**118,526**	131,856	144,455
Average net production gas (boe/d)	**9,425**	10,481	7,973
Combined price ($/boe)	**37.60**	41.67	53.72
Combined netback ($/boe)	**17.34**	21.83	32.64
Combined operating cost ($/boe)	**20.26**	19.84	21.08
Capital expenditures	**48,349**	18,804	185,043
Financials			
Total oil and gas sales and trading sale ($)	**376,403**	456,831	702,733
Adjusted EBITDA (1)	**100,356**	163,712	307,265
Adjusted EBITDA margin (adjusted EBITDA/revenues)	**27%**	36%	44%
Per share - basic ($) (2)	**0.32**	0.52	0.98
Funds flow from operations (1)	**(6,947)**	143,102	168,546
Funds flow from operations margin (funds flow from operations/revenues)	**(2)%**	31%	24%
Per share - basic ($) (2)	**(0.02)**	0.45	0.54
Net loss from operations before impairment and exploration expenses	**(88,178)**	(80,454)	(101,949)
Net loss (3)	**(118,654)**	(900,949)	(226,377)
Per share - basic ($) (2)	**(0.38)**	(2.86)	(0.72)

1. See "Additional Financial Measures" on page 31.
2. The basic weighted average numbers of common shares for the quarter ended June 30, 2016 and 2015, were 315,021,198 and 313,255,053, respectively.
3. Net loss attributable to equity holders of the parent.

	Q2 2016			Q2 2015		
	Oil & Gas	Trading	Total	Oil & Gas	Trading	Total
Volume sold (boe/d)	**109,736**	**288**	**110,024**	**132,417**	**10,808**	**143,225**
Average realized price ($/boe)	**37.60**	**36.79**	**37.59**	**53.72**	**56.29**	**53.92**
Financial results (in thousands of US$)						
Revenues	**375,438**	**965**	**376,403**	**647,367**	**55,366**	**702,733**
Cost of operations	**202,220**	**665**	**202,885**	**254,025**	**52,747**	**306,772**
Production and purchase cost of barrels sold	87,069	665	87,734	115,055	52,747	167,802
Transportation cost (trucking and pipeline) (1)	111,941	-	111,941	156,325	-	156,325
Diluent cost	19,954	-	19,954	22,466	-	22,466
Other costs (royalties paid in cash)	(16,599)	-	(16,599)	7,697	-	7,697
Overlift/underlift	(145)	-	(145)	(47,518)	-	(47,518)
Gross margin	**173,218**	**300**	**173,518**	**393,342**	**2,619**	**395,961**

1. For the second 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 $17.4 million and $10.1 million, respectively. Refer to Note 15 of the Interim Condensed Consolidated Financial Statements for additional details.

Results

Operational

- For the three months ended June 30, 2016, the Company saw an average daily net production after royalties of 127,951 boe/d, a 16% decrease compared with 152,428 boe/d for the same period in 2015. This is mainly attributable to a natural decline occurring due to decreased drilling activity due to current market conditions. The decrease in production was also the result of lower investments due to the expiration of the Rubiales field contract and the suspension of production in Block 192 in Peru due to disruptions to oil pipelines.
- During the second quarter of 2016, the Company continued to streamline its operations to further reduce costs. The Company achieved an underlying combined operating cost of $21.93/boe and a total combined operating cost (including overlift and other costs) of $20.26/boe, compared with $24.38/boe and $21.08/boe, respectively, in the same period of 2015. In the first quarter of 2016, the total combined operating cost was $19.84/boe.
- On June 30, 2016, the Rubiales and Piriri fields were returned to Ecopetrol S.A. (“**Ecopetrol**”) upon the expiration of the joint operating agreements.

Financial

- Revenue decreased to $376 million compared with the $457 million in the first quarter of 2016, reflecting lower volumes sold during the quarter. Revenue decreased by $327 million compared with $703 million for the second quarter of 2015, mainly due to lower realized prices.
- Average oil and gas sales (including trading) for the second quarter of 2016 were 110,024 boe/d, 23% lower than the 143,225 boe/d in the second quarter of 2015.
- Combined oil and gas operating netback for the quarter was $17.34/boe, 47% lower than $32.64/boe in the second quarter of 2015. The decrease was mainly attributable to the decline in market prices for crude oil and lower sales during the quarter. The Company’s average sales price per barrel of crude oil and natural gas was $37.60/boe for the quarter, down from $53.72/boe in the same period of 2015.
- Adjusted EBITDA for the quarter was $100 million, lower by 67% compared with the same period of 2015.

- General and Administrative ("**G&A**") costs decreased to $38 million in the second quarter of 2016 from $51 million in the same period of 2015, as the Company continued to control G&A and all non-essential spending activities in light of the decrease in oil prices.
- Net loss for the period was $119 million, largely due to including $48 million of costs related to the restructuring and impairment and exploration expenses of $23 million.
- Total capital expenditures decreased to $48 million in the second quarter of 2016, compared with $185 million in the same period of 2015.

Going Concern Uncertainty

- On April 27, 2016 the Company obtained an Initial Order from the Court under the CCAA, which (i) authorizes the Filing Entities to commence a Court-supervised proceeding in respect of the Restructuring Transaction; (ii) provides protections to allow normal operations to continue as the Filing Entities proceed to consummate the Restructuring Transaction with certain noteholders, lenders and The Catalyst Capital Group Inc.; and (iii) approves the DIP Financing, all as part of the Restructuring Transaction.
- There is no certainty as to the Company's ability to successfully restructure its long-term debts pursuant to the Restructuring Transaction, and amend the relevant operating agreements to eliminate credit rating covenants should low crude prices persist, and accordingly, there is a material uncertainty that may cast significant doubt on the Company's ability to continue as a going concern. For more information, refer to Note 2 in the Interim Condensed Consolidated Financial Statements.

3 Operating Netbacks

Oil & Gas Operating Netback

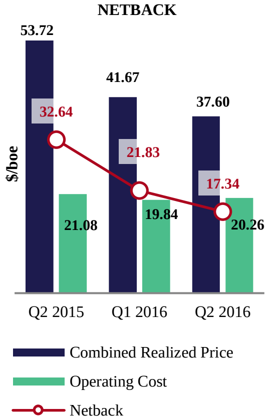
Combined operating netbacks during the three months ended June 30, 2016, and March 31, 2016 are summarized below.

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

	Three Months Ended June 30 2016			Three Months Ended March 31 2016		
	Crude Oil	Natural Gas	Combined	Crude Oil	Natural Gas	Combined
Average daily volume sold (boe/day)[1]	**100,778**	**8,958**	**109,736**	**110,010**	**10,210**	**120,220**
Operating netback ($/boe)						
Crude oil and natural gas sales price	38.77	24.44	37.60	43.20	25.29	41.67
Production cost of barrels sold [2]	9.24	2.81	8.72	9.36	3.54	8.86
Transportation (trucking and pipeline) [3]	12.15	0.60	11.21	13.48	(0.05)	12.32
Diluent cost	2.18	-	2.00	2.60	-	2.38
Total operating cost	**23.57**	**3.41**	**21.93**	**25.44**	**3.49**	**23.56**
Other costs [4]	(1.81)	-	(1.66)	(0.60)	-	(0.55)
Overlift/underlift [5]	-	(0.13)	(0.01)	(3.45)	(0.17)	(3.17)
Total operating cost including overlift/underlift, royalties paid in cash and other costs	**21.76**	**3.28**	**20.26**	**21.39**	**3.32**	**19.84**
Operating netback crude oil and gas ($/boe)	**17.01**	**21.16**	**17.34**	**21.81**	**21.97**	**21.83**

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 crude oil and gas through pipelines and tank trucks incurred by the Company when taking the products to delivery points for customers, storage costs and external road maintenance at the fields. For the three months ended June 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 first half of 2015.
5. Corresponds to the net effect of the overlift position of $0.1 expense during the second quarter of 2016 ($48 million expense for the second quarter of 2015).

COMBINED OPERATING NETBACK



During the second quarter of 2016, the Company's average combined realized price decreased from $41.67/boe in the first quarter of 2016 to $37.60/boe, mainly due to realized gains from price-hedging of $14.77/boe during the first quarter of 2016. The realized oil price decreased from an average of $43.20/bbl in the first quarter of 2016 to an average of $38.77/bbl.

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 $23.56/boe in the first quarter of 2016 to $21.93/boe for the second quarter of 2016. Total combined operating costs increased from $19.84/boe in the first quarter of 2016 to an average of $20.26/boe for the second quarter of 2016, mainly due to an overlift settlement during first quarter of 2016. The increased total combined unit cost was mainly a result of lower volumes sold during the period. During the second quarter of 2016, there was a 29-day disruption of the Bicentenario pipeline. However, the Company was able to source available operational capacity to the OCENSA pipeline at comparable costs per unit.

Combined operating netbacks for the second quarters of 2016 and 2015 are summarized below.

	Three Months Ended June 30					
	2016			2015		
	Crude Oil	Natural Gas	Combined	Crude Oil	Natural Gas	Combined
Average daily volume sold (boe/day)(1)	**100,778**	**8,958**	**109,736**	**124,416**	**8,001**	**132,417**
Operating netback ($/boe)						
Crude oil and natural gas sales price	38.77	24.44	37.60	55.04	33.34	53.72
Production cost of barrels sold (2)	9.24	2.81	8.72	9.89	4.28	9.55
Transportation (trucking and pipeline) (3)	12.15	0.60	11.21	13.76	0.85	12.97
Diluent cost	2.18	-	2.00	1.98	-	1.86
Total operating cost	**23.57**	**3.41**	**21.93**	**25.63**	**5.13**	**24.38**
Other costs (4)	(1.81)	-	(1.66)	0.67	0.07	0.64
Overlift/underlift (5)	-	(0.13)	(0.01)	(4.20)	0.10	(3.94)
Total operating cost including overlift/underlift, royalties paid in cash and other costs	**21.76**	**3.28**	**20.26**	**22.10**	**5.30**	**21.08**
Operating netback crude oil and gas ($/boe)	**17.01**	**21.16**	**17.34**	**32.94**	**28.04**	**32.64**

Notes: Refer to the operating netback table on page 7.

For the second quarter of 2016, the combined crude oil and gas operating netback was $17.34/boe, $15.30/boe lower than the same period of 2015 ($32.64/boe), and the crude oil operating netback specifically was $17.01/bbl, $15.93/bbl lower than the same period of 2015 ($32.94/bbl). The lower netback was mainly attributable to the decline in crude oil prices, an event which resulted in lower realized price of $37.60/boe on a combined basis for the three months ended June 30, 2016, compared with $53.72/boe in the same period of 2015. At the same time, the Company achieved a reduction in total operating costs (including overlifts/underlifts and other costs) of $0.82/boe to $20.26/boe. Reductions in field costs were achieved through a number of initiatives, including streamlining the workforce.

Trading Netback

	Three Months Ended		
Crude oil trading	June 30		March 31
	2016	2015	2016
Average daily volume sold (bbl/d)	**288**	**10,808**	**347**
Operating netback ($/bbl)			
Crude oil traded sales price	36.79	56.29	28.95
Cost of purchases of crude oil traded	25.35	53.63	26.61
Operating netback crude oil trading ($/bbl)	**11.44**	**2.66**	**2.34**

In the second quarter of 2016, the Company traded an average of 288 bbl/d compared with 10,808 bbl/d in the same period of 2015. The average netback for volumes traded in the second quarter of 2016 was $11.44/bbl (a gross margin of $0.3 million) versus the netback obtained in the same period of 2015 of $2.66/bbl (a gross margin of $2.6 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

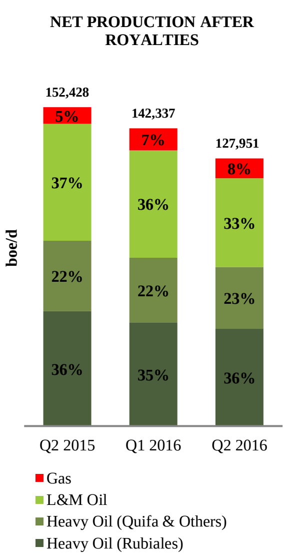
Production and Development Review

During the second quarter of 2016, net production after royalties and internal consumption totalled 127,951 boe/d, a decrease of 14,386 boe/d (10%) from the average net production of 142,337 boe/d reported in the first quarter of 2016.

During the second quarter of 2016, light and medium net oil production totalled 42,453 bbl/d, decreasing by 10% from the first quarter of 2016. The decrease is mainly attributable to the natural decline of the Llanos oil fields, which have not been sustained by drilling activity; additionally, Peru production decreased mainly due to the suspension of operations in Block 192. Heavy oil production from Quifa and other fields decreased by 4% during the second quarter of 2016 compared with the previous quarter. Light and medium oil and heavy crude oil production (excluding production at the Rubiales field) now represents 33% and 23%, respectively, of total net oil and gas production.

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

Second Quarter 2016 Production



	Average Production (in boe/d)						
	Total field production		Gross share before royalties [1]		Net share after royalties		
Producing fields in Colombia	**Q2 2016**	**Q2 2015**	**Q2 2016**	**Q2 2015**	**Q2 2016**	**Q1 2016**	**Q2 2015**
Rubiales / Piriri	137,747	163,815	58,104	68,697	46,483	49,486	54,958
Quifa SW [2]	49,046	56,192	29,133	33,367	26,430	27,551	29,906
	186,793	**220,007**	**87,237**	**102,064**	**72,913**	**77,037**	**84,864**
Other fields in Colombia							
Light and medium [3]	44,938	59,117	42,383	56,229	40,352	45,202	52,249
Gas [4]	10,476	8,788	9,425	7,973	9,425	10,481	7,973
Heavy oil [5]	4,419	5,844	3,302	3,989	3,160	3,533	3,808
	59,833	**73,749**	**55,110**	**68,191**	**52,937**	**59,216**	**64,030**
Total production Colombia	**246,626**	**293,756**	**142,347**	**170,255**	**125,850**	**136,253**	**148,894**
Producing fields in Peru							
Light and medium [6]	5,223	7,592	2,101	3,534	2,101	6,084	3,534
	5,223	**7,592**	**2,101**	**3,534**	**2,101**	**6,084**	**3,534**
Total production Colombia and Peru	**251,849**	**301,348**	**144,448**	**173,789**	**127,951**	**142,337**	**152,428**

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 125,850 boe/d (246,626 boe/d total field production) for the second quarter of 2016, down from 148,894 boe/d (293,756 boe/d total field production) in the same period of 2015, and 8% lower than 136,253 boe/d in the first quarter of 2016 (267,684 boe/d total field production).

Reduced production at the Rubiales field was primarily due to natural decline. The Rubiales and Piriri fields were returned to Ecopetrol upon the expiration of the joint agreements on June 30, 2016. The Company and Ecopetrol have signed a termination agreement for the return of the Rubiales and Piriri fields, and are continuing negotiations to conclusively settle certain outstanding obligations. Pursuant to the Rubiales-Piriri contract, all fixed assets located in the field are transferred to Ecopetrol along with the operatorship without compensation. Both parties have agreed on a settlement agreement for the smooth transition of the operatorship, with certain adjustments to be finalized in the near future, including production volume adjustment, inventory and material transfers, and certain abandonment obligations.

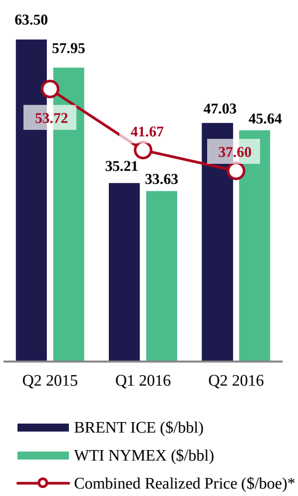
Peru

The Company's production from Peru consist of 49% participating interest in Block Z-1, 30% working interest in the Los Angeles discovery in Block 131, and the Block 192 operation contract. Net production after royalties for the second quarter of 2016 totalled 2,101 bbl/d, a 65% decrease from 6,084 bbl/d in the first quarter of 2016, mainly due to the suspension of operations in Block 192 as the result of a rupture to the NorPeruano pipeline in February.

Sales, Trading and Pricing

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

PRICES



* *Excluding Trading*

	Average Volume of Sales and Prices		
Colombia and Peru	**Q2 2016**	**Q1 2016**	**Q2 2015**
Oil (bbl/d)	101,855	111,188	127,738
Gas (boe/d)	8,958	10,210	8,001
Trading (bbl/d)	288	347	10,808
Total barrels sold (boe/d)	**111,101**	**121,745**	**146,547**
Sales from E&E assets (boe/d) (1)	(1,077)	(1,178)	(3,322)
Net barrels sold (in boe/d)	**110,024**	**120,567**	**143,225**
Realized prices			
Oil realized price ($/bbl)	38.77	43.20	55.04
Gas realized price ($/boe)	24.44	25.29	33.34
Combined realized price oil and gas $/boe (excluding trading)	37.60	41.67	53.72
Trading realized price ($/bbl)	36.79	28.95	56.29
Reference market prices			
WTI NYMEX ($/bbl)	45.64	33.63	57.95
ICE BRENT ($/bbl)	47.03	35.21	63.50
Guajira Gas Price ($/MMBtu) (2)	5.93	5.93	5.08
Henry Hub average Natural Gas Price ($/MMBtu)	2.25	1.98	2.74

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 2015 by the market operator as defined in CREG Resolution 089, 2013.

During the three months ended June 30, 2016, average oil and gas sales (including trading) totalled 110,024 boe/d, a decrease of 23% from the 143,225 boe/d in the same period of 2015, mainly due to a natural oil production declines.

The crude oil and gas combined realized price for the three months ended June 30, 2016, reached $37.60/boe, $16.12/boe lower than the same period of 2015.

For the second quarter of 2016, the WTI NYMEX price decreased by $12.31/bbl (21%) to an average of $45.64/bbl, compared with the average of $57.95/bbl in the same period of 2015. Likewise, the ICE BRENT price declined by $16.47/bbl (26%) to an average of $47.03/bbl, compared with the average of $63.50/bbl in the same period of 2015.

5 Financial Results

Revenues

(in thousands of US$)	Three Months Ended June 30 2016	Three Months Ended June 30 2015	Six Months Ended June 30 2016	Six Months Ended June 30 2015
Net crude oil and gas sales	$ 375,438	$ 647,367	$ 831,354	$ 1,379,679
Trading revenue	965	$ 55,366	1,880	122,902
Total sales	**$ 376,403**	**$ 702,733**	**$ 833,234**	**$ 1,502,581**
$ per boe oil and gas	37.60	53.72	39.73	51.36
$ per bbl trading	36.79	56.29	32.52	51.62
$ Total average revenue per boe	**37.59**	**53.92**	**39.71**	**51.39**

The following is an analysis of the revenue drivers of price and volume for the second quarter of 2016 in comparison with the same period of 2015.

	Three Months Ended June 30 2016	2015	Difference	Change (%)
Total of boe sold (Mboe)	10,012	13,033	(3,021)	(23)%
Avg. combined price - oil & gas and trading ($/boe)	37.59	53.92	(16.33)	(30)%
Total revenue	**$ 376,403**	**$ 702,733**	**$ (326,331)**	**(46)%**

Drivers for the revenue decrease:		
Due to volume	$ (162,904)	50%
Due to price	(163,427)	50%
	$ (326,331)	

During the second quarter of 2016, revenues totalled $376 million, 46% lower than the same period of 2015, wherein revenues totalled $703 million. This decrease is the result of lower realized oil prices and lower volumes sold.

Revenue for the six months ended June 30, 2016, were $833 million, 45% lower than the same period of 2015, which had revenues of $1,503 million.

Operating Costs

(in thousands of US$)	Three Months Ended June 30 2016	Three Months Ended June 30 2015	Six Months Ended June 30 2016	Six Months Ended June 30 2015
Production cost of barrels sold	$ 87,069	$ 115,055	$ 184,022	$ 245,780
Per boe	8.72	9.55	8.79	9.15
Transportation cost (1)	111,941	156,325	246,779	322,196
Per boe (1)	11.21	12.97	11.80	11.99
Diluent cost	19,954	22,466	45,953	47,709
Per boe	2.00	1.86	2.20	1.78
Other cost	(16,599)	7,697	(22,575)	20,688
Per boe	(1.66)	0.64	(1.08)	0.77
Overlift/underlift	(145)	(47,518)	(34,835)	13,287
Per boe	(0.01)	(3.94)	(1.66)	0.49
Operating cost	**202,220**	**$ 254,025**	**419,344**	**$ 649,660**
Average operating cost per boe	**$ 20.26**	**21.08**	**$ 20.05**	**24.18**
Take-or-pay fees on disrupted transport capacity Bicentenario	18,058	27,492	43,449	30,277
Per boe	1.81	2.28	4.13	2.47
Trading purchase cost	665	52,747	1,506	116,763
Per bbl	25.35	53.63	51.96	99.45
Total cost	**$ 220,943**	**$ 334,264**	**$ 464,299**	**$ 796,700**

1. For the three months ended June 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 $17.4 million and $10.1 million, respectively. Refer to Note 15 of the Interim Condensed Consolidated Financial Statements for additional details.

Total operating costs for the second quarter of 2016 were $221 million, which includes the Company's $17.4 million share of income from equity investments in the ODL and Bicentenario pipelines and $18 million ($1.81/boe) in net take-or-pay fees paid to Bicentenario for non-available capacity. When the Bicentenario pipeline was suspended for 29 days for security issues, the Company used a combination of available capacity on the OCENSA pipeline and trucking to move oil to the export ports. For the second quarter of 2016, total operating costs were $221 million, a 34% decrease compared to $334 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 $53 million in the second quarter of 2015 to $1 million in the second quarter of 2016, mainly due to lower sales volumes.

Depletion, Depreciation and Amortization

	Three Months Ended June 30		Six Months Ended June 30	
(in thousands of US$)	2016	2015	2016	2015
Depletion, depreciation and amortization	$ 145,891	$ 397,739	$ 376,483	$ 804,158
$/per boe sales (own production)	14.61	33.01	17.99	29.94

For the second quarter of 2016, DD&A costs were $146 million, compared to $398 million for the same period of 2015. The 63% decrease is primarily due to the lower carrying amount of oil & gas properties resulting from the impairments recognized during 2014, 2015 and first quarter of 2016. Unit DD&A for the second quarter 2016 was $14.61/boe, 56% lower than the $33.01/boe for the same period of 2015. During the first half of 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 June 30		Six Months Ended June 30	
(in thousands of US$)	2016	2015	2016	2015
Impairment and exploration expenses	$ 22,788	$ -	$ 689,686	$ 448,967

The Company assesses at the end of each reporting period 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 include 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 the oil & gas, exploration and evaluation properties.

The Company's impairment tests of oil and gas and 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. For the three and six months ended June 30, 2016 the recoverable amount was determined based on the fair value less cost to sell (2015: value-in-use).

As at June 30, 2016, as a result of indicators of impairment the Company recorded an impairment charge on their Exploration and Evaluation assets in the amount of $22.8 million. The impairment recognized during the period relates to the Company's limited ability to fund future Exploration and Evaluation assets.

For the six months ended June 30, 2016, the Company recorded a total impairment charge of $689.7 million as detailed below:

(in thousands of US$)	Three Months ended June 30 2016		Three Months ended June 30 2015		Six Months ended June 30 2016		Six Months ended June 30 2015
Oil and Gas Properties (D&P)							
Colombia properties (Central CGU)	$	-	$	-	$	503,004	$ -
Peru properties		-		-		70,000	-
Plant and Equipment (PP&E)		-		-		30,994	-
Exploration and Evaluation Properties (E&E)							
Colombia		4,134		-		4,300	112,000
Belize		186		-		368	-
Peru		664		-		9,427	33,000
Brazil		17,789		-		18,713	35,000
Papua New Guinea		-		-		-	13,000
Other		-		-		18	8,000
Total Impairment Impact D&P, PP&E and E&E	**$**	**22,773**	**$**	**-**	**$**	**636,824**	**$ 201,000**
Impairment of other assets		-		-		52,595	-
Goodwill allocated to Colombia		-		-		-	237,009
Total impairment	**$**	**22,773**	**$**	**-**	**$**	**689,419**	**$ 438,009**

During the first quarter 2016 and as a result of the Restructuring Transaction entered into on April 19, 2016 (Please refer to "Corporate Restructuring Transaction section" on page 1), the Company believed there was an indication of impairment as of March 31, 2016. The Company performed a test of impairment of the carry amounts of its long-term assets against the higher of their value-in-use and the fair value less cost to sell.

Total impairment and exploration expenses are summarized below:

(in thousands of US$)	Three Months Ended June 30 2016		Three Months Ended June 30 2015		Six Months Ended June 30 2016		Six Months Ended June 30 2015
Impairment	$	22,773	$	-	$	689,419	$ 438,009
Impairment of financial assets		15		-		267	10,958
Total	**$**	**22,788**	**$**	**-**	**$**	**689,686**	**$ 448,967**

General and Administrative Costs

(in thousands of US$)	Three Months Ended June 30 2016		Three Months Ended June 30 2015		Six Months Ended June 30 2016		Six Months Ended June 30 2015
General and administrative costs	$	37,685	$	51,104	$	71,499	$ 106,009
$/per boe sales		3.76		3.92		3.41	3.63

G&A costs decreased to $38 million in the second quarter of 2016 from $51 million in the same period of 2015, mainly due to the adoption of cost optimization initiatives. G&A per boe decreased by $0.16/boe to $3.76/boe from $3.92/boe in the same period of 2015.

Restructuring Costs

(in thousands of US$)	Three Months Ended June 30 2016		Three Months Ended June 30 2015		Six Months Ended Montly 2016		Six Months Ended Montly 2015
Restructuring costs	$	47,940	$	-	$	64,720	$ -

During the three and six months ended June 30, 2016, the Company incurred $47.9 million and $64.7 million in costs related to the signing of the Forbearance Agreement and Comprehensive Restructuring Agreement. These restructuring costs were predominantly the appointment of independent financial and legal advisors to assist with the ongoing negotiations and counsel all counter parties involved.

Finance Costs and Foreign Exchange

(in thousands of US$)	Three Months Ended June 30 2016		Three Months Ended June 30 2015		Six Months Ended June 30 2016		Six Months Ended June 30 2015
Finance costs	$	32,891	$	78,117	$	101,805	$ 156,975

Finance costs include interest on the Company's bank loans, senior notes, revolving credit facilities, working capital loans and finance leases; fees on letters of credit; and net of interest income received. For the three months ended June 30, 2016, finance costs totalled $33 million, lower than $78 million in the same period of 2015. The Senior Notes and the credit facilities ceased to accrue interest on April 27, 2016, as a result of the Company receiving the initial court order for the Restructuring Transaction.

	Three Months Ended June 30		Six Months Ended June 30	
(in thousands of US$)	2016	2015	2016	2015
Foreign exchange gain (loss)	$ 8,518	$ (5,414)	$ 5,179	$ (41,194)

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 operating and capital expenditures, as well as assets and liabilities, are denominated in COP. During the second quarter of 2016, the COP appreciated against the U.S. dollar by 3.51%, compared with a depreciation of 0.35% during the same period of 2015. Foreign exchange gain for the three months ended June 30, 2016, was $9 million, compared with a loss of $5 million in the same period of 2015.

Income Tax Expense

	Three Months Ended June 30		Six Months Ended June 30	
(in thousands of US$)	2016	2015	2016	2015
Current income tax	$ (8,594)	$ (12,000)	$ (20,088)	$ (30,193)
Deferred income tax	(30)	64,158	1,516	103,845
Total income tax (expense) recovery	**$ (8,624)**	**$ 52,158**	**$ (18,572)**	**$ 73,652**

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

The Colombian statutory tax rate for the second 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 back 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 June 30, 2016 and 2015 respectively. The Peruvian income tax rate for Block Z-1 was 22% for the quarters ended June 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 3.51% during the second quarter of 2016, which resulted in an estimated unrealized deferred income tax recovery of $0.03 million. In comparison, the Company recorded $21.4 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 0.35%.

Excluding the effect from the above-mentioned foreign exchange fluctuations, the effective tax rate for the Company was (8.8%) and 27.7% for the three months ended June 30, 2016 and 2015, respectively.

	Three Months Ended June 30		Six Months Ended June 30	
(in thousands of US$)	2016	2015	2016	2015
Apreciation (depreciation) of the COP against the U.S. dollar	3.5%	(4.0)%	7.4%	(8.1)%
Net loss before income tax	97,530	265,463	988,524	1,011,433
Current income tax expense	(8,594)	(12,000)	(20,088)	(30,193)
Deferred income tax	(30)	64,158	1,516	103,845
Total income tax (expense) recovery as reported	**(8,624)**	**52,158**	**(18,572)**	**73,652**
Excluding effect from depreciation of COP	-	21,476	-	139,143
Total income tax (expense) recovery excluding the above effects	**(8,624)**	**73,634**	**(18,572)**	**212,795**
Effective tax rate excluding effect of COP apreciation/depreciation	**(8.8)%**	**27.7%**	**(1.9)%**	**21.1%**
Effective tax rate including effect of COP apreciation/depreciation	**(8.8)%**	**19.6%**	**(1.9)%**	**7.3%**

During the second quarter 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 $20.1 million in the second half of 2016 as compared to $30.2 million in the same period of 2015. The reduction is mainly attributable to lower taxable revenues as a result of the significant drop in international oil prices.

The 2016 wealth tax paid totaled $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

	Three Months Ended June 30		Six Months Ended June 30	
(in thousands of US$)	2016	2015	2016	2015
Production facilities	$ 15,379	$ 34,832	$ 19,826	$ 60,483
Exploration activities	21,994	47,833	22,526	107,117
Early facilities and others	867	1,462	2,459	1,849
Development drilling	6,649	93,331	15,615	213,852
Other projects	3,460	7,585	6,727	27,776
Total capital expenditures	**$ 48,349**	**$ 185,043**	**$ 67,153**	**$ 411,077**

Capital expenditures during the second quarter of 2016 totalled $48 million, $137 million lower than the $185 million in the second quarter of 2015. A total of $15 million was invested in the expansion and construction of production infrastructure, primarily in Rubiales, Quifa SW, Cubiro, Cravoviejo, La Creciente, Arrendajo, Guama, Corcel, Guatiquia, Neiva, Block 131 and Block Z-1 fields; $22 million went into exploration activities mainly invested in Brazil; $1 million went into facilities and others; $7 million went into development drilling; and $3 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 approximately equal cash flow.

Financial Position

Debts and Credit Instruments

The following debts were outstanding as at June 30, 2016.

Senior Unsecured Notes

The Company has a number of series of senior unsecured notes outstanding with an aggregate principal of $4.1 billion as at December 31, 2015. The senior notes are listed on the Official List of the Luxembourg Stock Exchange and are guaranteed by the Company's main operating subsidiaries. The maturities of the senior notes range from 2019 to 2025, and the interest rates range 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 limits the Company's ability to incur additional debt, subject to various exceptions including certain refinancing transactions.

The senior notes represent almost 79% of the Company's outstanding debt.

The Senior Notes and the credit facilities ceased to accrue interest on April 27, 2016, as a result of the Company receiving the initial court order for the Restructuring Transaction.

Revolving Credit Facilities

On February 5 and March 13, 2015, the Company drew down $100 million and $900 million, respectively, from the $1 billion unsecured revolving Credit and Guaranty Agreement (the "**Revolving Credit Facility**"). Using the proceeds from the draw down, the Company repaid short-term bank loans in the aggregate principal amount of $383.8 million.

On March 3, 2015, the Company agreed with its syndicate of lenders to amend the Revolving Credit Facility. Under the amended terms of the Revolving Credit Facility, the Company's permitted consolidated leverage ratio (debt-to-EBITDA) was increased from 3.5:1.0 to 4.5:1.0 based on a rolling four-quarter average. The other two financial covenants were not amended, being: (i) the maintenance of an interest coverage ratio of greater than 2.5; and (ii) a net worth of greater than $1 billion, calculated as total assets less total liabilities, excluding those of certain subsidiaries, specifically Pacific Midstream Ltd. and Pacific Infrastructure Ventures Inc.

Under the terms of the Revolving Credit Facility and the Company's other credit facilities, the financial covenants are "maintenance-based covenants"; the Company must maintain compliance with the financial (in thousands of US$) metrics in order to avoid default. For practical purposes, these are checked quarterly over a previous twelvemonth basis. If at such time the financial debt ratios are not met, this may result in an acceleration in part or in whole of the indebtedness, or restrict the Company's ability to take on additional debt or carry out certain specified M&A operations, subject to various exemptions.

On November 27, 2015, the Company agreed with Bladex to prepay the Bladex credit facility in the amount of $50.6 million, and in return, Bladex provided Letters of Credit for the same amount. Subsequent to December 31, 2015, the Company made two additional prepayments, on January 8, 2016 for $17.2 million and on February 3, 2016, for $7.1 million, at which time the Bladex facility was fully repaid and cancelled. Additionally, on February 19, 2016, the outstanding balance of the bilateral entered into with Bank of America was reduced in the amount of $33.4 million, and the outstanding balance under such credit facility is of $ 2.9 million.

Restructuring Transaction

As previously mentioned, on April 27, 2016 the Company obtained an Initial Order from the Superior Court of Justice in Ontario under the Companies' Creditors Arrangement Act ("CCAA"), which (i) authorizes the Filing Entities (as previously defined) to commence a Court-supervised restructuring proceeding; (ii) provides protections to allow normal operations to continue as the Filing Entities proceed to consummate the Restructuring Transaction further to Pacific's previously announced agreement with certain noteholders, lenders and The Catalyst Capital Group Inc.; and (iii) approves the DIP Financing, all as part of the Restructuring Transaction.

On June 22, 2016 the Company closed the DIP Financing in the amount of $500 million, less original issue discount, with: (i) certain holders of the Company's senior unsecured notes and (ii) Catalyst . 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.

Letters of Credit

As at June 30, 2016, the Company had issued letters of credit and guarantees for exploration and operational commitments for a total of approximately $172 million.

Oil Price Hedging

In the second quarter of 2016, after having unwound the hedging portfolio, the Company was fully exposed to oil price volatility and therefore took advantage of the Brent price upward trend during the quarter from the lowest level of $37.27/bbl up to the highest of $52.86/bbl. As a result, the market value of the Company's crude oil export portfolio improved and consequently its operating revenue and net back for the quarter benefited. There were no realized gains from oil price-hedging activity for the quarter as no additional volumes were hedged.

On July 21, 2016, the Company entered into a zero cost collared forward sale contract with a floor price of $46.00/bbl and a ceiling of $49.60/bbl ICE Brent (subject a price differential on the Brent), whereby the Company shall deliver 500,000 bbl per month starting September 2016 until February 2017.

Outstanding Share Data

Common shares

As at August 11, 2016, 316,094,858 common shares were issued and outstanding.

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

Stock options and warrants

As at August 11, 2016, there were 6,250,000 warrants outstanding that were issued as part of the Restructuring Transaction. A total of 12,245,867 stock options were outstanding, of which all were exercisable. As of May 28, 2014, the Board of Directors committed to no longer granting stock options and instead has implemented a Deferred Share Unit ("**DSU**") Plan for eligible employees.

Deferred share units

As at August 11, 2016, there were 8,656,469 DSUs outstanding. DSUs are cash-settled instruments that track the price of the Common Shares and are payable to eligible participants upon their retirement, resignation, or termination from the Company.

Liquidity and capital resources

As at June 30, 2016, the Company had negative working capital of $5,479 million, mainly comprised of $599 million in cash and cash equivalents, $90 million in restricted cash, $307 million in accounts receivable, $72 million in inventory, $123 million in income tax receivable, $2 million in prepaid expenses, $862 million in accounts payable and accrued liabilities, $5,803 million in the current portion of long-term debt, $4 million in the current portion of obligations under finance lease, and $3 million in asset retirement obligations.

Funds flow provided by operating activities for the second quarter of 2016 totalled a deficit of $7 million (2015: $169 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 and production reduction.

Please refer to “Financial Results – Financial Position” on page 15 for details of certain events of default, covenant breaches and forbearance agreements in respect of the Company’s outstanding indebtedness. Refer to “Risks and Uncertainties” on page 35 for details of the risks and uncertainties relating to the Company’s liquidity and capital resources and ability to continue as a going concern.

6 Commitments and Contingencies

Tax Review in Colombia

The 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 six months ended June 30, 2016, the amounts reassessed, including interest and penalties, is estimated at $63.2 million, of which the Company estimates that $22 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, 2016, the DIAN released a general ruling to third party, 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 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 June 30, 2016, the DIAN has reassessed $63 million of tax owing, including estimated interest and penalties, with respect to the denied deductions.

As at June 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 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 was 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 will make the second installment 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 29 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 early-terminate the assignment agreement 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 September 15, 2016. 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 June 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 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 rights to receive a letter of credit which will expire once the project is complete and operational. No provision has been recognized as of June 30, 2016 relating to the breach of the credit rating requirement.

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 which 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 has created the New Business Opportunities Committee ("**NBOC**") to review and approve related-party transactions. The NBOC was comprised of the following independent directors: Hernan Martinez (Chair), Dennis Mills, Monica De Greiff and Francisco Solé. The NBOC is apprised of related-party transactions prior to implementation, engages independent legal counsel as needed, and meets *in camera* to deliberate. The NBOC also reviews the business rationale for each transaction and ensures that they are in compliance with applicable securities laws and the Company's debt covenants.

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, is considered similar to those negotiable with third parties.

The following sets out the details of the Company's related-party transactions:

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 24.9% indirect interest and Genser Power Inc. ("**Genser**") which is 51% owned by Pacific Power. On March 1, 2013, these contracts were assigned to TermoMorichal SAS ("**TermoMorichal**"), the company created to perform the agreements, in which Pacific Power 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 June 30, 2016, the Company had an advance of $Nil (December 2015: $3.3 million).

   The Company had accounts payable of $4 million (December 2015: $3.6 million) due to Genser-Proelectrica as at June 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 six months ended June 30, 2016 the Company made payments of $9.2 million and $15.3 million respectively (2015: $13.6 million and $26.6 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 six months ended June 30, 2016, the Company recorded revenues of $1.8 million and $7.7 million respectively (2015: $0.6 million and $1.3 million) from such agreements. As at June 30, 2016, the Company had trade accounts receivable of $1.2 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) As at June 30, 2016, the Company had trade accounts receivable of $1.2 million (December 31, 2015: $12.3 million) from Proelectrica, in which the Company has a 21.1% indirect interest and which is 5% owned by Blue Pacific Assets Corp. ("Blue Pacific"). Two executive directors and an officer of the Company (Serafino Iacono, Miguel de la Campa, and Laureano von Siegmund), along with Jose Francisco Arata, an executive director of the Company until August 14, 2015, control or provide investment advice to the holders of 88% of shares of Blue Pacific. The Company and Blue Pacific's indirect interests are held through Pacific Power. Revenue from Proelectrica in the normal course of the Company's business was $1.8 million and $7.7 million for the three and six months ended June 30, 2016 (2015: $0.6 million and $1.3 million).

c) As at June 30, 2016, loans receivable from related parties in the aggregate amount of $0.4 million (December 31, 2015: $0.5 million) are due from one executive director (Serafino Iacono) and six officers (Carlos Perez, Luis Andres Rojas, Francisco Bustillos, Luciano Biondi, Jairo Lugo and Marino Ostos) 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 Jose Francisco Arata, 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 June 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. Also during 2015, the Company made payments in kind of approximately 0.5 million common shares to three departing directors (Victor Rivera, Miguel Rodriguez, and Neil Woodyer) as settlement for DSU entitlements.

d) The Company has take-or-pay contracts with ODL for the transportation of crude oil from Company's fields to Colombia's oil transportation system for a total commitment of $198 million from 2016 to 2020. During the three and six months ended June 30 2016, the Company paid $21.8 million and $51.4 million respectively to ODL (2015: $19.8 million and $54.2 million) for crude oil transport services under the pipeline take-or-pay agreement, and had accounts payable of $11.5 million (December 31, 2015: $13.1 million). In addition, the Company received $0.1 million and $0.2 million from ODL during the three and six months ended June 30, 2016 (2015: $0.6 million and $1 million) with respect to certain administrative services and rental equipment and machinery. The Company accounts receivable from ODL as at June 30, 2016 of $0.1 million (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 Company's fields to Colombia's oil transportation system for a total commitment of $1.4 billion from 2016 to 2025. The Bicentenario pipeline has experienced periodic suspensions following security-related disruptions. During the three and six months ended June 30, 2016, the Company paid $29.1 million and $79.4 million respectively to Bicentenario (2015: $59 million and $86.9 million), a pipeline company in which the Company has a 27.9% interest, for crude oil transport services under the pipeline ship-or-pay agreement. As at June 30, 2016, the balance of loans outstanding to Bicentenario was $Nil (December 31, 2015: $Nil). Interest income of $Nil and $Nil was recognized during the three six months ended June 30, 2016 (2015: $0.4 million and $1 million).

Interest of $Nil and $Nil was paid on the loans during the three and six months ended June 30, 2016 (2015:Nil and $1.3 million), and capital of $Nil and $Nil was paid on the loans in the three and six months ended in June 30, 2016 (2015: $Nil and $17.2 million). The Company has advanced $87.9 million as at June 30, 2016 (December 31, 2015: $87.9 million) to Bicentenario as a prepayment of transport tariff, which is amortized against the barrels transported. As at June 30, 2016 the Company had trade accounts receivable of $3.7 million (December 31, 2015: $0.4 million) as a short-term advance.

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 six months ended June 30, 2016, the Company contributed $1.7 million and $5.3 million respectively to these foundations (2015: $4.2 million and $6.7 million). At as June 30, 2016, the Company had accounts receivable (advances) of $0.4 million (December 31, 2015: $0.4 million) and accounts payable of $0.6 million (December 31, 2015: $3.2 million). Three of the Company's 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) At as June 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 $1.3 million and $2.6 million was recognized during the three and six months ended June 30, 2016 (2015: $1.3 million and $2.5 million) regarding to the loan. In addition, during the three and six months ended June 30, 2016, the Company received $0.5 million and $2.6 million (2015: $3 million and $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 June 30, 2016, the Company had accounts receivable of $2.4 million (December 31, 2015: $0.5 million) from a branch of PII. As at June 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; its majority shareholder is AVF, which is controlled by Blue Pacific. As part of the purchase, CRC also assigned 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. The Company currently has an 9.63% equity interest in CRC. In addition, the Company has an indirect equity interest of 9.84% in CRC through its 21.1% ownership of Pacific Power, which in turn has a 46.67% equity interest in CRC. A director of the Company, is the Executive Chairman of CRC.

i) The Company has a lease agreement for an office in Caracas, Venezuela for approximately $6 thousand per month. The office space is 50% owned by a family member of an executive officer of the Company (Laureano von Siegmund).

j) On February 29, 2016, the Company agreed to provide CGX with a bridge loan of up to $2 million at an interest rate of 2% per annum and payable within 12 months of the first draw down. As at June 30, 2016, the amount CGX had drawn down from the bridge loan was $1.3 million.

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

k) During the three and six months ended June 30, 2016, the Company received cash of $10.9 million and $22.9 million respectively in accordance with its joint operations obligation associated with its 49% interest in Block Z-1 in Peru. In addition, the Company had accounts receivable of $Nil under the joint operation agreement from ALFA S.A.B de C.V. ("**Alfa**") who owns a 51% working capital interest in Block Z-1 and also holds 18.95% of the issued and outstanding capital of the Company.

l) As of June 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 the 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. Pacific Green is controlled by two executive directors and one officer of the Company (Laureano von Siegmund, Serafino Iacono, and Miguel de la Campa).

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

The Company used most of the proceeds from the sale to pay for its share of a put option that was exercised by Sustainable Services Inc., pursuant to the terms of a pre-existing shareholder agreement between Pacific Power and its shareholders.

8 Selected Quarterly Information

	2016		2015				2014			
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financials:										
Net sales	$ 376,403	$ 456,831	$ 651,970	$ 669,995	$ 702,733	$ 799,848	$ 991,508	$ 1,330,395	$ 1,344,666	$ 1,283,453
Net (loss) earnings attributable to equity holders of the parent for the period	(118,654)	(900,949)	(3,895,908)	(617,318)	(226,377)	(722,256)	(1,660,876)	3,484	228,527	119,240
(Loss) Earnings per share										
- basic	(0.38)	(2.86)	(12.37)	(1.97)	(0.72)	(2.31)	(5.26)	0.01	0.73	0.38
- diluted	(0.38)	(2.86)	(12.37)	(1.97)	(0.72)	(2.31)	(5.26)	0.01	0.72	0.37

9 Accounting Policies, Critical Judgments, and Estimates

Basis of Presentation

The Interim Condensed Consolidated Financial Statements accompanying this MD&A for the three months ending June 30, 2016 and 2015 have been prepared in accordance with IFRS as issued by the IASB, including the accounting policies and critical judgments and estimates as disclosed in Note 2 of the Interim Condensed Consolidated Financial Statements.

These 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.

For the six months ended June 30, 2016, the Company incurred a net loss of $1,007 million and has a deficit of $3,962 million as of June 30, 2016.

On January 14, 2016, the Company announced it had elected to utilize the 30-day grace period under the applicable note indentures and not make interest payments of $66.2 million in the aggregate on its September 2014 Senior Notes and November 2013 Senior Notes (Note 18 of the Interim Condensed Consolidated Financial Statements) as they became due on January 19, 2016 and January 26, 2016, respectively. The failure to pay such interest constituted an event of default under the applicable note indentures on February 25, 2016 in respect of the September 2014 Senior Notes and February 18, 2016 in respect of the November 2013 Senior Notes.

On March 28, 2016, the Company announced it had elected to utilize the 30-day grace period under the applicable note indentures and not make interest payments of $25.6 million in the aggregate on its March 2013 Senior (Note 18 of the Interim Condensed Consolidated Financial Statements) as they became due on March 28, 2016. The failure to pay such interest on April 27, 2016 did not constitute an event of default under the applicable note indentures.

The Company has also breached several minimum credit rating covenants in respect to certain operational agreements it has entered into, as a result of downgrades of the Company's credit rating during 2015. Consequently, the counterparties of these operational agreements have the option to demand a range of remedies including letters of credit and penalties. Waivers related to these credit rating covenants have been granted, refer to Note 21 for more details. There is no assurance that the Company will be able to successfully negotiate amendments to the minimum credit rating requirements or obtain future extensions of these waivers.

There can be no certainty as to the ability of the Company to successfully restructure its long-term debts (further explained below in "Comprehensive Restructuring Agreement") and amend the relevant operating agreements to eliminate credit rating covenants should low crude prices persist, and accordingly, there is a material uncertainty that may cast significant doubt on the Company's ability to continue as a going concern. These financial statements do not include adjustments to the recoverability and classification of recorded assets and liabilities and related expenses that might be necessary should the Company be unable to continue as a going concern and therefore be required to realize its assets and liquidate its liabilities and commitments in other than the normal course of business at amounts different from those in the accompanying consolidated financial statements. Such adjustments could be material.

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, except for the adoption of new standards and interpretations effective as of 1 January 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 1 January 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 do 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, 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 nontrading 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 24 July 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 rising 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 recognise revenue. The core principle is that an entity will recognise 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, 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 be 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; and
- Identifying best practices and process improvement opportunities.

During the second quarter of 2016, 309 controls were tested over the 626 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 June 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 the 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; and
- 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 June 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; and
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 June 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 which 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 $41 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

Introduce the study for modify the Environmental Licence in La Creciente field; the project modification involves:

- Extend production facilities to 15 Hectares.
- Obtain permit to inject industrial water.

On June 7, 2016, the Autoridad Nacional de Licencias Ambientales ("**ANLA**") granted the environmental licence in the Cubiro Central field, which includes:

- 19 platforms construction with up to five production wells for total of 95 wells.
- Industrial water injection permission for 26 new wells.
- Construction of 34 km of new roads.
- Construction of two new production facilities of ten Hectares each one.

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

The Company uses the financial measure "Adjusted EBITDA" in this MD&A, whereas in the past we have used the term "EBITDA." Our calculation of this measure has not changed from previous quarters, but the terminology has changed due to guidance provided by the Ontario Securities Commission. 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:

	Three Months Ended June 30		Six Months Ended June 30	
(in thousands of US$)	**2016**	**2015**	**2016**	**2015**
Net loss (1)	**$ (118,654)**	**$ (226,377)**	**(1,019,603)**	**$ (948,633)**
Adjustments to net loss				
Income tax expense (recovery)	8,624	(52,158)	18,572	(73,652)
Foreign exchange (gain) loss	(8,518)	5,414	(5,179)	41,194
Finance cost	32,891	78,117	101,805	156,975
(Gain) loss on risk management contracts	(6,073)	68,470	107,472	68,637
Gain of equity-accounted investees	(29,526)	(13,901)	(56,373)	(31,354)
Other (income) expenses	(2,210)	25,414	(44,420)	46,984
Share-based compensation	(5,297)	11,475	(8,503)	13,561
Equity tax	-	-	26,901	39,149
Gain attributable to non-controlling interest	12,500	13,072	12,507	10,852
Depletion, depreciation and amortization	145,891	397,739	376,483	804,158
Impairment and exploration expenses	22,788	-	689,686	448,967
Restructuring Costs	47,940	-	64,720	-
Adjusted EBITDA	**$ 100,356**	**$ 307,265**	**$ 264,068**	**$ 576,838**

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

Funds Flow from Operations

	Three Months Ended June 30		Six Months Ended June 30	
(in thousands of US$)	**2016**	**2015**	**2016**	**2015**
Cash flow from operating activities	$ (8,310)	$ 97,311	$ (44,036)	$ 196,257
Changes in non-cash working capital	1,363	70,915	105,191	341,918
Deferred revenue net proceeds	-	320	75,000	(199,155)
Funds flow from operations	**$ (6,947)**	**$ 168,546**	**$ 136,155**	**$ 339,020**

Net Loss from Operations

(in thousands of US$)	Three Months Ended June 30 2016	Three Months Ended June 30 2015	Six Months Ended June 30 2016	Six Months Ended June 30 2015
Net loss [1]	**$ (118,654)**	**$ (226,377)**	**(1,019,603)**	**$ (948,633)**
Finance costs	32,891	78,117	101,805	156,975
Gain of equity-accounted investees	(29,526)	(13,901)	(56,373)	(31,354)
Equity tax	-	-	26,901	39,149
Foreign exchange (gain) loss	(8,518)	5,414	(5,179)	41,194
(Gain) loss on risk management contracts	(6,073)	68,470	107,472	68,637
Other (income) expenses	(2,210)	25,414	(44,420)	46,984
Income tax expense (recovery)	8,624	(52,158)	18,572	(73,652)
Gain attributable to non-controlling interest	12,500	13,072	12,507	10,852
Net loss from operations	**$ (110,966)**	**$ (101,949)**	**$ (858,318)**	**$ (689,848)**

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

We fulfilled our commitment with Colombia in the Rubiales field

The work carried out by the Company in the Rubiales field during the past eight years is a testament that sustainability is in Pacific’s DNA and is a significant part of its legacy. Faithful to its Sustainability Policy, the Company worked hand-in-hand with all of its stakeholders, and contributed to build a more stable and prosperous region. Under Pacific’s operation, the Rubiales field received the EO100 sustainable barrel certification for three consecutive years. The EO100 evaluates metrics and performance targets that address the social and environmental impacts of oil and gas exploration and production companies, including freedom of association, labour rights, security, and human rights.

Some of the highlights of our operation:

Economic: With the experience and knowledge of Pacific’s teams, the Company was able to achieve record gross production which translated into a 700% increase in royalty payments. The Company believed that its presence in these areas of operation had to serve as a catalyst for local and regional growth, and as such it financed the formalization of more than 170 small-and-medium sized companies in the Puerto Gaitan Municipality, leading them to increase their revenue by more than 70%. Through this initiative, Pacific and its contractors purchased more than $40 million, improving the lives of hundreds of families, while generating competitive operational costs. Also, during its time as operator, the Company contributed to developing important infrastructure such as the ODL pipeline and the Petroelectrica power transmission line which represented important savings to the Company and also decreased its environmental footprint in terms of emissions.

Social: The Company’s operation created more than 25,000 jobs for Colombians who carried out our activities in line with the best health and safety standards in accordance to the OSHAS 18001 certification. Wanting to go beyond employment, we improved the quality of life of more than 22,000 inhabitants of Puerto Gaitan through the development of educational, health, infrastructure, culture, and local supplier strengthening initiatives. In accordance with our Stakeholder Engagement Policy, we created negotiation round tables to make sure our decisions reflected their expectations, a practice which has been recognized by several organizations. Given that in the beginning of our operations the area surrounding the field was considered a high risk conflict area, we created specific guidelines and procedures set to avoid any human rights violations and promoted actively these amongst our stakeholders; proof of the latter was our entrance into the Voluntary Principles organization.

Environmental: The Rubiales field is located in an environment with rich biodiversity, requiring a holistic management to avoid degradation. To guarantee the latter, the operation had in place important management systems such as the ISO 14001 that required it to have state of the art biodiversity monitoring systems and contingency plans, waste disposal mechanisms, integral water management procedures and targeted emission control. With this in place, the Company managed to have zero significant environmental incidents. Additionally, the Company obtained the ISO 50001 certification for its reinjection pads, certifying that its pads were efficient and thereby emitted less emissions. Pacific was the first company in Latin America to obtain this certification. The Agrocascada water treatment plant, established to reduce operational costs and provide a use of residual water for local agricultural projects, garnered support of international organizations and was subject of many recognitions.

The Company will continue to build on the lessons learnt in Rubiales and apply its sustainability model throughout all its operations.

Update on the Constitutional Court decision in the Quifa block:

As reported in the first quarter, the Company complied with the Constitutional Court’s decision and carried out the consultation process with the Vencedor Piriri community during April 2016.

After reaching an agreement to compensate the activities described in the ruling, the Company notified the Court of its compliance and currently operations are in full force and effect. Towards the end of June 2016, the Company conducted a series of meetings with the aforementioned indigenous community as to define the investment projects through the scope of the community’s life plan. We hope to execute these projects throughout 2016.

Update on our Peruvian operations:

Block 137 was awarded to the company in the year 2007. As part of its Human Right’s commitment, the Company did not enter the block until it had free, prior and informed consent by the indigenous communities in the area. Accordingly, due to a lack of agreement between the Peruvian State, the Company and the Communities, the block was declared in force majeure in 2008 and, to date, the company has not carried out activities within the territory. Given the latter and out of respect for the community’s will, on June 17, 2016, the company notified Perupetro of its decision to terminate the contract. The termination will be effective as of July 17, 2016, with no associated penalties.

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.

These risks and uncertainties include the fact that, despite a number of cost reduction initiatives that have been implemented by the Company, at current oil prices the Company has required, and may in the future again require, new financing to fund its interest payments and debt repayments as they come due, and possibly operating cash needs. As mentioned above, on April 27, 2016 the Company obtained an Initial Order from the Superior Court of Justice in Ontario (the "**Court**") under the Companies' Creditors Arrangement Act ("**CCAA**"), which (i) authorizes the Filing Entities to commence a Court-supervised restructuring proceeding; (ii) provides protections to allow normal operations to continue as the Filing Entities proceed to consummate a proposed comprehensive restructuring transaction (the "**Restructuring Transaction**") further to Pacific's previously announced agreement with certain noteholders, lenders and The Catalyst Capital Group Inc.; and (iii) approves: the DIP Financing, all as part of the Restructuring Transaction. There can be no certainty as to the ability of the Company to successfully restructure its long-term debts, and, if required, obtain additional financing should low crude prices persist. Furthermore, there is a material uncertainty that may cast doubt on the Company's ability to continue as a going concern *upon completion 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. 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 2016 primarily through cash on hand, proceeds from the DIP Financing and cash flows from operations, although these sources may not be sufficient to fund such requirements.

To continue as a going concern, the Company must generate sufficient operating cash flows, secure additional capital or otherwise pursue a strategic restructuring, refinancing or other transactions (including the Restructuring Transaction) to provide it with additional liquidity. The Company cannot provide any assurance that any of these actions can be effected on a timely basis, on satisfactory terms or maintained once initiated. If they are not, the Company's liquidity and results of operations will be materially adversely affected and the Company would not be able to continue as a going concern. Moreover, the Company's ability to successfully implement, and the cost of, any such transactions (including the Restructuring Transaction) will depend on numerous factors, including:

- Demand and prices for oil and natural gas;
- General economic conditions;
- The strength of the credit and capital markets;
- The Company's ability to successfully execute its operational strategies, and its operating and financial performance;
- The Company's ability to comply with the covenants in its debt instruments;
- The Company's ability to comply with its operating agreements;
- The Company's ability to maintain relationships with its suppliers, customers, employees, stockholders and other third parties; and
- Market uncertainty in connection with the Company's ability to continue as a going concern as well as investor confidence in the Company.

Other material risk factors include, but are not limited to:

- the Company's ability to continue as a going concern upon completion of the Restructuring Transaction;
- failure of the Company to complete the Restructuring Transaction, which is subject to a number of conditions and other risks and uncertainties; court and required regulatory approvals or otherwise;
- the effect of the Restructuring Transaction on the Company's business and operations;

- Volatility in market prices for oil and natural gas;
- A continued depressed oil price environment with the potential of further decline;
- Any negative impact on the Company’s current operations as a result of any proposed restructuring or failure to implement the Restructuring Transaction;
- Investors’ perceptions of the Company’s prospects and the prospects of the oil and gas industry in Colombia and the other countries where the Company operates and/or has investments;
- Expectations regarding the Company’s ability to raise capital and to continually add to reserves through acquisitions and development;
- inability to obtain a listing on the an stock exchange as is acceptable to the Company and others as required by the Restructuring Transaction;
- The effect of ratings downgrades on the Company’s business and operations;
- Political developments in Colombia, Guatemala, Peru, Brazil, Guyana and Mexico;
- Liabilities inherent in oil and gas operations;
- Uncertainties associated with estimating oil and natural gas reserves;
- Competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel, among other things;
- Incorrect assessments of the value of acquisitions and/or past integration problems;
- Geological, technical, drilling and processing problems;
- Fluctuations in foreign exchange or interest rates and stock market volatility;
- Delays in obtaining required environmental and other licences;
- Uncertainty of estimates of capital and operating costs, production estimates and estimated economic return;
- The possibility that actual circumstances will differ from estimates and assumptions;
- Uncertainties relating to the availability and costs of financing needed in the future; and finally,
- Changes in income tax laws or changes in tax laws, accounting principles and incentive programs relating to the oil and gas industry.

The Company’s Annual Information Form dated March 18, 2016 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, contains 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.

Translation

This MD&A was prepared originally in the English language and subsequently translated into Spanish. In the case of differences or discrepancies between the original and the translated versions, the English document shall prevail and be treated as the governing version.

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