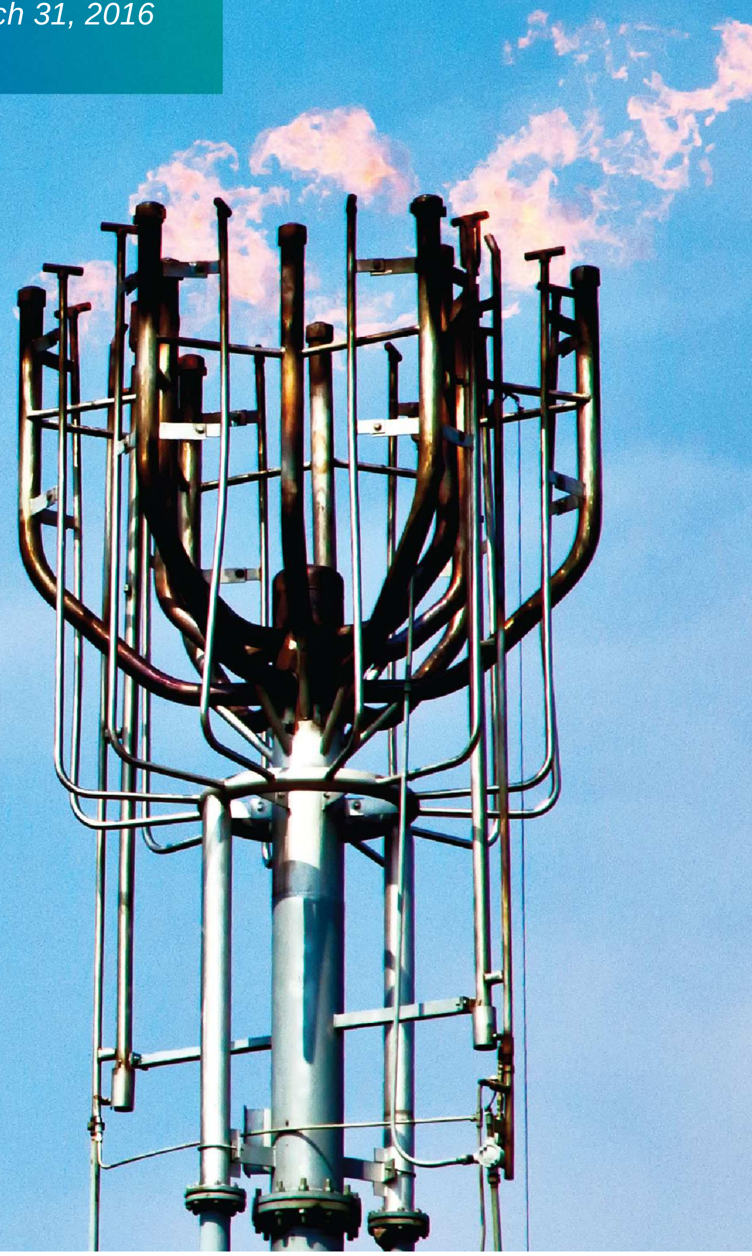
PACIFIC E&P

MANAGEMENT DISCUSSION & ANALYSIS

May 13, 2016

For the three months ended March 31, 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 March 31, 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 March 31, 2016 and 2015, unless otherwise noted.

In order to provide shareholders with full disclosure relating to potential future capital expenditures, the Company has provided cost estimates for projects that in some cases are still in the early stages of development. These costs are preliminary estimates only. The actual amounts are expected to differ, and these differences may be material. For further discussion of the significant capital expenditures, see "Capital Expenditures" on page 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 versions, 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 taking steps to protect its integrity while also addressing covenants in place on the various bonds and bank facilities. At the end of the third quarter and into the fourth quarter, the Company was able to obtain covenant relief. However, as oil prices deteriorated in the middle of the fourth quarter, the Company appointed a financial advisor (Lazard Freres & Co. LLC) to assist in negotiations with a lender steering committee representing the syndicate of lenders holding the $1.0 billion revolving credit facility.

In mid-January 2016, the Company announced its intention to use the 30-day grace period with respect to upcoming bond interest payments but also indicated that it would engage with its creditors (bondholders and banks) with a goal 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 evaluate all strategic options available.

In late February, the Company commenced a formal solicitation process to solicit interest from prospective investors with respect to either (i) an investment to effect the Company's recapitalization or (ii) an acquisition of all or part of Pacific's assets.

After an extensive competitive bid solicitation process involving the submission of six bids and direct negotiations among the bidders, the Ad Hoc Committee (which comprised holders of the Company's senior unsecured notes), and the Supporting Bank Lenders (certain of the Company's lenders under its credit facilities), the Board of Directors, acting on a recommendation from the Independent Committee of the Board of Directors, approved a comprehensive restructuring transaction (the "**Restructuring Transaction**"). 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 (the "**Court**") under the Companies' Creditors Arrangement Act ("**CCAA**"). This authorized the Filing Entities to commence the court-supervised Restructuring Transaction previously announced 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; and (iii) certain of the Company's lenders unders its credit facilities.

The Restructuring Transaction is a comprehensive financial restructuring plan that will significantly reduce debt, improve liquidity and best position the Company to navigate the current oil price environment as proposed by Catalyst. The Restructuring Transaction represents the culmination of a thorough solicitation process with cooperative and direct negotiations among the Company, the Ad Hoc Committee, the Supporting Bank Lenders and each of the bidders, including Catalyst. To facilitate this process, the Independent Committee allowed all of the bidders to disclose their offers to, and negotiate directly with, the Ad Hoc Committee and the Supporting Bank Lenders after submitting their binding offers.

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 (a) the application for protection, filed on April 27, 2016, under the CCAA with the Court in Ontario, and (b) the initial order obtained from the Court, on April 27, 2016, pursuant to the CCAA.

The Catalyst Transaction

During the Restructuring Transaction, operations of the Company’s subsidiaries (the “**Pacific Group**”) will continue as normal and without disruption. It is anticipated that all obligations to the Pacific Group's suppliers, trade partners and contractors will 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 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 will jointly provide $500 million of debtor-in-possession financing (the “**DIP Financing**”) less an original issue discount of 4%. The DIP Financing will be 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).
- The providers of the DIP Financing will receive warrants to acquire their pro-rata share of 25% of the fully diluted common shares of the reorganized Company on implementation of the Restructuring Transaction.
- The Funding Creditors will provide $250 million of the DIP Financing (the “**Creditor DIP Financing**”). The Creditor DIP Financing will not be repaid at exit of the Restructuring Transaction and will convert into five-year secured notes on customary terms.
- Catalyst will provide $250 million of the DIP Financing (the “**Catalyst DIP Financing**”). On implementation of the Restructuring Transaction, the Catalyst DIP Financing will be converted or exchanged for 16.8% of the common shares of the reorganized Company. Catalyst has agreed to backstop the Creditor DIP Financing.
- 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 fully extinguished and exchanged for 58.2% of the common shares of the reorganized Company (subject in the case of the noteholders to dilution arising from the Supporting Noteholder Consideration, as described below) (the “**Affected Creditor Consideration**”).
- 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 the Cash Out Offer (as defined below). It is contemplated that the cash election (the “**Cash Out Offer**”) will be available to all Affected Creditors and based on a structure backstopped by Catalyst. Specifically, Catalyst has agreed to subscribe for no less than $200 million of equity in the reorganized Company at an equity valuation of no less than $800 million on the effective date of the Restructuring Transaction. The Affected Creditors will not be required to participate in the Cash Out Offer. As the cash available under the Cash Out Offer will be limited by the amount of the additional equity Catalyst subscribes for, under certain circumstances, the Cash Out Offer may be subject to proration.
- The DIP Financing and the Restructuring Transaction will be subject to certain conditions, including creditor and court approval, which will be 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 $253 million. Following the conclusion of the Restructuring Transaction, the $250 million of new secured notes will be the only debt in the Company's capital structure outside of unfunded facilities to support letters of credit or hedging activities.

- It is anticipated that certain of the Supporting Bank Lenders will provide a letter of credit facility of up to $134 million to the reorganized Company.
- The Company has agreed to a “no shop” provision with Catalyst for a period of up to 12 weeks in accordance with the terms of its commitment with Catalyst.
- Under the terms of the DIP Financing, a break fee equal to 5% of the aggregate principal amount of the DIP Financing shall be payable by the Company to Catalyst and the Funding Creditors in the event the DIP Financing or the Restructuring Transaction is not consummated in accordance with the terms of the DIP Financing. The Company has agreed to pay Catalyst’s out-of-pocket expenses in connection with the Restructuring Transaction.
- No Company equity will be awarded to management or the Company’s executive co-chairmen (other than pro-rata treatment in respect to any unsecured notes they held) on implementation of the Restructuring Transaction.
- Given the significant impairments to the Company’s bank indebtedness and indebtedness with respect to its senior unsecured notes (and the treatment of such indebtedness pursuant to the Restructuring Transaction), the Company’s existing outstanding common shares will be (i) cancelled for no consideration or (ii) subject to extensive dilution such that, following the completion of the Restructuring Transaction, existing holders of common shares will hold in the aggregate only a nominal amount of the reorganized Company’s equity and associated voting power. If the holdings of the existing shareholders are extensively diluted, such diluted, nominal holdings will decrease, pro rata, the percentage holdings of common shares of the reorganized company to be held by Catalyst, the Funding Creditors and the Affected Creditors as set out above.
- 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**”). The assumption of “control” is an administrative procedure available to the Superintendence that allows the Superintendence to take any preventative or remedial actions that it considers necessary to allow a corporation to resolve critical legal, accounting, economic or other issues. As ordered by the Superintendence pursuant to its control power, the granting of security over the assets of the Colombian Branches, the transfer of their assets and transactions by the Colombian Branches outside the ordinary course of business will each require the prior consent of the Superintendence. The general control powers granted to the Superintendence by the applicable law include: (i) promotion of plans or arrangement to improve the situation of a corporation that is subject to such control powers; (ii) authorization of amendments to the by-laws of a corporation that is subject to such control powers; (iii) authorization for the issuance and placement of shares of a corporation that is subject to such control powers, (iv) authorization of the granting of security over corporate assets, transfers of corporate assets and transactions outside the ordinary course of business; (v) removal of the administrators and internal auditors of a corporation that is subject to such control powers, when irregularities in their actions deem it necessary; and (vi) the commencement of plenary reorganization procedures, among others.

2 Highlights for the Three Months Ended March 31, 2016

Financial and Operating Summary

(in thousands of US$ except per share amounts or as noted)	Q1 2016	Q4 2015	Q1 2015
Operating activities			
Average sales volumes (boe/d)	**120,567**	171,928	180,086
Average oil and gas sales (boe/d)	**120,220**	171,039	164,562
Average trading sales (bbl/d)	**347**	889	15,524
Average net production (boe/d)	**142,337**	159,831	152,650
Average net production oil (bbl/d)	**131,856**	149,368	144,094
Average net production gas (boe/d)	**10,481**	10,463	8,556
Combined price ($/boe)	**41.67**	41.22	49.45
Combined netback ($/boe)	**21.83**	18.70	22.73
Combined operating cost ($/boe)	**19.84**	22.52	26.72
Capital expenditures	**18,804**	160,154	226,034
Financials			
Total oil and gas sales and trading sale ($)	**456,831**	651,970	799,848
Adjusted EBITDA[(1)]	**163,712**	182,917	269,573
Adjusted EBITDA margin (adjusted EBITDA/revenues)	**36%**	28%	34%
Per share - basic ($) [(2)]	**0.52**	0.58	0.86
Funds flow from operations[(1)]	**143,102**	42,277	170,474
Funds flow from operations margin (funds flow from operations/revenues)	**31%**	6%	21%
Per share - basic ($) [(2)]	**0.45**	0.13	0.54
Net loss from operations before impairment and exploration expenses	**(80,454)**	(198,814)	(138,932)
Net loss[(3)]	**(900,949)**	(3,895,908)	(722,256)
Per share - basic ($) [(2)]	**(2.86)**	(12.37)	(2.31)

1. See “Additional Financial Measures” on page 32.
2. The basic weighted average numbers of common shares for the quarter ended March 31, 2016 and 2015, were 315,021,198 and 313,255,053, respectively.
3. Net loss attributable to equity holders of the parent.

Breakdown of Oil & Gas and Trading Results

	Three Months Ended March 31					
	2016			2015		
	Oil & Gas	Trading	Total	Oil & Gas	Trading	Total
Volume sold (boe/d)	**120,220**	**347**	**120,567**	**164,562**	**15,524**	**180,086**
Average realized price ($/boe)	**41.67**	**28.95**	**41.64**	**49.45**	**48.34**	**49.35**
Financial results (in thousands of US$)						
Revenues	**455,916**	**915**	**456,831**	**732,312**	**67,536**	**799,848**
Cost of operations	**217,124**	**841**	**217,965**	**395,635**	**64,016**	**459,651**
Production and purchase cost of barrels sold	96,953	841	97,794	130,725	64,016	194,741
Transportation cost (trucking and pipeline) (1)	134,838	-	134,838	165,871	-	165,871
Diluent cost	25,999	-	25,999	25,243	-	25,243
Other costs (royalties paid in cash)	(5,976)	-	(5,976)	12,991	-	12,991
Overlift/underlift	(34,690)	-	(34,690)	60,805	-	60,805
Gross margin	**238,792**	**74**	**238,866**	**336,677**	**3,520**	**340,197**

1. For the three months ended March 31, 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 $15.9 million and $12.9 million, respectively. Refer to Note 15 of the Interim Condensed Consolidated Financial Statements for additional details.

Highlights

Operational

- For the three months ended March 31, 2016, the Company saw an average daily net production after royalties of 142,337 boe/d, a 7% decrease compared with 152,650 boe/d for the same period in 2015. This is mainly attributable to a natural decline occurring due to decreased drilling activity, resulting from current market conditions and matching capital expenditures to approximate cash flow in the quarter.
- During the first quarter of 2016, the Company continued to streamline its operations to further reduce costs. The Company achieved an underlying combined operating cost of $23.56/boe and a total combined operating cost (including overlift and other costs) of $19.84/boe, compared with $21.73/boe and $26.72/boe, respectively, in the same period of 2015. In the fourth quarter of 2015, the total combined operating cost was $22.52/boe.

Financial

- Revenue decreased to $457 million compared with the $652 million in the fourth quarter of 2015, reflecting lower volumes sold during the quarter, partially compensated by hedging gains, which helped to support the Company's realized prices. Revenue decreased by $343 million compared with $800 million for the first quarter of 2015, mainly due to lower realized prices.
- Average oil and gas sales (including trading) for the first quarter of 2016 were 120,567 boe/d, 33% lower than the 180,086 boe/d in the first quarter of 2015.
- In the first quarter of 2016, revenue included $162 million in realized gains from oil hedging contracts entered in early 2015, helped support the Company's realized prices above global benchmarks. In February 2016, the Company early terminated its outstanding hedging positions early, taking advantage of the positive mark-to-market generating cash and improving liquidity.
- Combined oil and gas operating netback for the quarter was $21.83/boe, 4% lower than $22.73/boe in the first quarter of 2015. The decrease was mainly attributable to the decline in market prices for crude oil, partially offset by the strong hedging position that generated higher realized prices. The Company's average sales price per barrel of crude oil and natural gas was $41.67/boe for the quarter, down from $49.45/boe in the same period of 2015.

- Adjusted EBITDA for the quarter was $164 million, and funds flow was $143 million. Adjusted EBITDA and funds flow were 39% and 16% lower, respectively, compared with the same period of 2015.
- G&A expenses decreased to $34 million in the first quarter of 2016 from $55 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 $901 million, largely due to $27 million of equity tax expense and $667 million non-cash impairment charge taken mainly on oil and gas assets and exploration expenses, reflecting the significant decline in crude oil prices.
- Total capital expenditures decreased to $19 million in the first quarter of 2016, compared with $226 million in the same period of 2015.

Going Concern Uncertainty

- Despite a number of cost reduction initiatives that the Company has implemented, with the current oil prices, the Company will likely need new financing to fund its interest payments and debt repayments as they come due, and possibly to fulfill operating cash needs. As mentioned above, 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 restructuring proceeding; (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: (i) a U.S. $500 million debtor-in-possession financing facility and a super priority lien over assets of the Filing Entities to secure the obligations under that facility; and (ii) a U.S. $134 million letter of credit facility and a second priority lien over assets of the Filing Entities to secure the obligations under that facility, 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

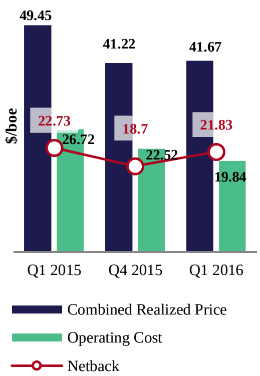
Our operating costs continued decreasing in 2016 as a result of strategies for streamlining production costs and optimizing field operations.

Combined operating netbacks during the three months ended March 31, 2016, and December 31, 2015 are summarized below.

	Three Months Ended March 31			Three Months Ended December 31		
	2016			2015		
	Crude Oil	Natural Gas	Combined	Crude Oil	Natural Gas	Combined
Average daily volume sold (boe/day)[1]	**110,010**	**10,210**	**120,220**	**160,498**	**10,541**	**171,039**
Operating netback ($/boe)						
Crude oil and natural gas sales price	43.20	25.29	41.67	41.86	31.43	41.22
Production cost of barrels sold [2]	9.36	3.54	8.86	8.61	5.09	8.40
Transportation (trucking and pipeline)[3]	13.48	(0.05)	12.32	9.36	-	8.79
Diluent cost	2.60	-	2.38	2.26	-	2.12
Total operating cost	**25.44**	**3.49**	**23.56**	**20.23**	**5.09**	**19.31**
Other costs[4]	(0.60)	-	(0.55)	1.05	-	0.97
Overlift/underlift[5]	(3.45)	(0.17)	(3.17)	2.37	0.33	2.24
Total operating cost including overlift/underlift, royalties paid in cash and other costs	**21.39**	**3.32**	**19.84**	**23.65**	**5.42**	**22.52**
Operating netback crude oil and gas ($/boe)	**21.81**	**21.97**	**21.83**	**18.21**	**26.01**	**18.70**

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 March 31, 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 the net effect of the currency hedges of operating expenses incurred in Colombian pesos during the period.
5. Corresponds to the net effect of the overlift position of $34.7 million income during the first quarter of 2016 ($60.8 million expense for the first quarter of 2015).

COMBINED OPERATING NETBACK



During the three months ended March 31, 2016, the Company's average combined realized price increased from $41.22/boe in the fourth quarter of 2015 to $41.67/boe, despite the downward move in global oil prices. The realized oil price increased from an average of $41.86/bbl in the fourth quarter of 2015 to an average of $43.20/bbl as a result of the Company's hedging program.

After adapting to the low oil price environment in 2015, the Company continued to streamline operations to maintain cost efficciencies. Total combined operating costs decreased from $22.52/boe in the fourth quarter of 2015 to an average of $19.84/boe in the first quarter of 2016. Combined operating costs, including production, transportation and dilution costs, increased from $19.31/boe in the fourth quarter of 2015 to $23.56/boe for the first quarter of 2016. The increased unit cost was mainly a result of lower volumes sold during the period. During the first quarter of 2016, there was a 47-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 first quarters of 2016 and 2015 are summarized below.

	Three Months Ended March 31					
	2016			2015		
	Crude Oil	Natural Gas	Combined	Crude Oil	Natural Gas	Combined
Average daily volume sold (boe/day)[1]	**110,010**	**10,210**	**120,220**	**155,967**	**8,595**	**164,562**
Operating netback ($/boe)						
Crude oil and natural gas sales price	43.20	25.29	41.67	50.38	32.48	49.45
Production cost of barrels sold [2]	9.36	3.54	8.86	9.06	4.63	8.83
Transportation (trucking and pipeline)[3]	13.48	(0.05)	12.32	11.77	0.82	11.20
Diluent cost	2.60	-	2.38	1.80	-	1.70
Total operating cost	**25.44**	**3.49**	**23.56**	**22.63**	**5.45**	**21.73**
Other costs[4]	(0.60)	-	(0.55)	0.93	(0.07)	0.88
Overlift/underlift[5]	(3.45)	(0.17)	(3.17)	4.34	(0.08)	4.11
Total operating cost including overlift/underlift, royalties paid in cash and other costs	**21.39**	**3.32**	**19.84**	**27.90**	**5.30**	**26.72**
Operating netback crude oil and gas ($/boe)	**21.81**	**21.97**	**21.83**	**22.48**	**27.18**	**22.73**

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

For the first quarter of 2016, the combined crude oil and gas operating netback was $21.83/boe, $0.90/boe lower than the same period of 2015 ($22.73/boe), and the crude oil operating netback specifically was $21.81/bbl, $0.67/bbl lower than the same period of 2015 ($22.48/bbl). The lower netback was mainly attributable to the decline in crude oil prices, an event which resulted in lower realized price of $41.67/boe on a combined basis for the three months ended March 31, 2016, compared with $49.45/boe in the same period of 2015. At the same time, the Company achieved a significant reduction in total operating costs (including overlifts/underlifts and other costs) of $6.88/boe to $19.84/boe. Reductions in field costs were achieved through a number of initiatives, including streamlining the workforce.

Trading Netback

	Three Months Ended		
Crude oil trading	March 31		December 31
	2016	2015	2015
Average daily volume sold (bbl/d)	**347**	**15,524**	**889**
Operating netback ($/bbl)			
Crude oil traded sales price	28.95	48.34	40.89
Cost of purchases of crude oil traded	26.61	45.82	30.87
Operating netback crude oil trading ($/bbl)	**2.34**	**2.52**	**10.02**

In the first quarter of 2016, the Company traded an average of 347 bbl/d compared with 15,524 bbl/d in the same period of 2015. The average netback for volumes traded in 2016 was $2.34/bbl (a gross margin of $0.07 million) versus the netback obtained in the same period of 2015 of $2.52/bbl (a gross margin of $3.5million). 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

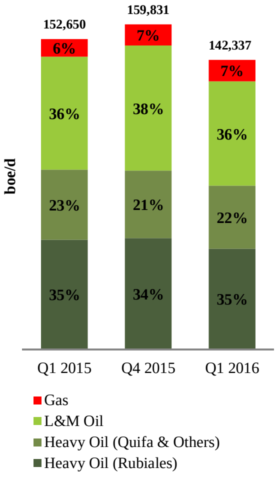
During the first quarter of 2016, net production after royalties and internal consumption totalled 142,337 boe/d, a decrease of 17,494 boe/d (11%) from the average net production of 159,831 boe/d reported in the fourth quarter of 2015.

During the first quarter of 2016, light and medium net oil production totalled 51,286 bbl/d, decreasing by 17% from the fourth quarter of 2015. 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 also decreased by 6% during the first quarter of 2016 compared with the fourth quarter of 2015. Light and medium oil and heavy crude oil production (excluding production at the Rubiales field) now represents 36% and 22%, respectively, of total net oil and gas production.

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

First Quarter 2016 Production

NET PRODUCTION AFTER ROYALTIES



Average Production (in boe/d)	Total field production		Gross share before royalties (1)		Net share after royalties		
Producing fields in Colombia	**Q1 2016**	**Q1 2015**	**Q1 2016**	**Q1 2015**	**Q1 2016**	**Q4 2015**	**Q1 2015**
Rubiales / Piriri	149,639	161,860	61,857	67,484	49,486	54,713	53,987
Quifa SW (2)	51,486	57,825	30,419	34,324	27,551	29,818	29,812
	201,125	**219,685**	**92,276**	**101,808**	**77,037**	**84,531**	**83,799**
Other fields in Colombia							
Light and medium (3)	50,205	59,982	47,453	56,753	45,202	50,959	52,731
Gas (4)	11,486	9,560	10,481	8,556	10,481	10,463	8,556
Heavy oil (5)	4,868	7,047	3,692	4,923	3,533	3,416	4,708
	66,559	**76,589**	**61,626**	**70,232**	**59,216**	**64,838**	**65,995**
Total production Colombia	**267,684**	**296,274**	**153,902**	**172,040**	**136,253**	**149,369**	**149,794**
Producing fields in Peru							
Light and medium (6)	9,928	6,442	6,084	2,856	6,084	10,462	2,856
	9,928	**6,442**	**6,084**	**2,856**	**6,084**	**10,462**	**2,856**
Total production Colombia and Peru	**277,612**	**302,716**	**159,986**	**174,896**	**142,337**	**159,831**	**152,650**

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, S.A. ("**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, Carbonera 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 136,253 boe/d (267,684 boe/d total field production) for the first quarter of 2016, down from 149,794 boe/d (296,274 boe/d total field production) in the same period of 2015, and 9% lower than 149,369 boe/d in the fourth quarter of 2015 (290,380 boe/d total field production).

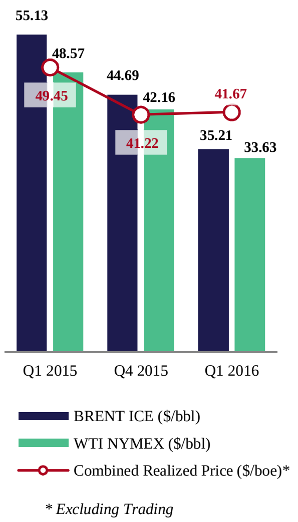
Reduced production at the mature Rubiales field was primarily due to restricted water disposal capacity as a result of delays in the environmental approval license for the Agrocascada water irrigation project. Plans to return the field to Ecopetrol in June 2016 are on schedule.

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 first quarter of 2016 totalled 6,084 bbl/d, by 42% decrease from 10,462 bbl/d in the fourth quarter of 2015, mainly due to suspension of operations in Block 192 as the result of a rupture of the NorPeruano pipeline in February.

Sales, Trading and Pricing

PRICES



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

	Average Volume of Sales and Prices		
Colombia and Peru	**Q1 2016**	**Q4 2015**	**Q1 2015**
Oil (bbl/d)	111,188	161,918	157,885
Gas (boe/d)	10,210	10,541	8,595
Trading (bbl/d)	347	889	15,524
Total barrels sold (boe/d)	**121,745**	**173,348**	**182,004**
Sales from E&E assets (boe/d) (1)	(1,178)	(1,420)	(1,918)
Net barrels sold (in boe/d)	**120,567**	**171,928**	**180,086**
Realized prices			
Oil realized price ($/bbl)	43.20	41.86	50.38
Gas realized price ($/boe)	25.29	31.43	32.48
Combined realized price oil and gas $/boe (excluding trading)	41.67	41.22	49.45
Trading realized price ($/bbl)	28.95	40.89	48.34
Reference market prices			
WTI NYMEX ($/bbl)	33.63	42.16	48.57
ICE BRENT ($/bbl)	35.21	44.69	55.13
Guajira Gas Price ($/MMBtu) (2)	5.93	5.44	5.08
Henry Hub average Natural Gas Price ($/MMBtu)	1.98	2.23	2.81

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.

The crude oil and gas combined realized price for the first quarter of 2016 was $41.67/boe, including a realized hedging gain of $14.77/boe, which helped to support the Company's realized prices above market rates during the quarter.

During the three months ended March 31, 2016, average oil and gas sales (including trading) totalled 120,567 boe/d, a decrease of 33% from the 180,086 boe/d in the same period of 2015, in part due to an overlift settlement of 14,733 boe/d as well as natural oil production declines.

The crude oil and gas combined realized price for the three months ended March 31, 2016, reached $41.67/boe, $7.78/boe lower than the same period of 2015. The combined realized price of $41.67/boe includes a realized oil price-hedging gain of $14.77/boe, which helped support the Company's realized prices above market rates during the year. See additional details under "Oil Price-Hedging" on page 16.

For the first quarter of 2016, the WTI NYMEX price decreased by $14.94/bbl (30.8%) to an average of $33.63/bbl, compared with the average of $48.57/bbl in the same period of 2015. Likewise, the ICE BRENT price declined by $19.92/bbl (36.1%) to an average of $35.21/bbl, compared with the average of $55.13/bbl in the same period of 2015.

5 Financial Results

Revenues

(in thousands of US$)	Three Months Ended March 31 2016	Three Months Ended March 31 2015
Net crude oil and gas sales	$ 455,916	$ 732,312
Trading revenue	915	67,536
Total sales	**$ 456,831**	**$ 799,848**
$ per boe oil and gas	41.67	49.45
$ per bbl trading	28.95	48.34
$ Total average revenue per boe	**41.64**	**49.35**

During the first quarter of 2016, revenues totalled $457 million, 43% lower than the same period of 2015, wherein revenues totalled $800 million. This decrease is the result of lower realized oil prices and lower trading volumes sold.

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

	Three Months Ended March 31 2016	Three Months Ended March 31 2015	Difference	Change (%)
Total of boe sold (Mboe)	10,972	16,208	(5,236)	(32)%
Avg. combined price - oil & gas and trading ($/boe)	41.64	49.35	(7.71)	(16)%
Total revenue	**$ 456,831**	**$ 799,848**	**$ (343,017)**	**(43)%**

Drivers for the revenue decrease:		
Due to volume	$ (258,404)	75%
Due to price	(84,613)	25%
	$ (343,017)	

Operating Costs

(in thousands of US$)	Three Months Ended March 31 2016	Three Months Ended March 31 2015
Production cost of barrels sold	$ 96,953	$ 130,725
Per boe	8.86	8.83
Transportation cost (1)	134,838	165,871
Per boe (1)	12.32	11.20
Diluent cost	25,999	25,243
Per boe	2.38	1.70
Other cost	(5,976)	12,991
Per boe	(0.55)	0.88
Overlift/underlift	(34,690)	60,805
Per boe	(3.17)	4.11
Operating cost	**217,124**	**$ 395,635**
Average operating cost per boe	**$ 19.84**	**$ 26.72**
Take-or-pay fees on disrupted transport capacity Bicentenario	25,391	2,785
Per boe	2.32	0.19
Trading purchase cost	841	64,016
Per bbl	26.61	45.82
Total cost	**$ 243,356**	**$ 462,436**

1. For the three months ended March 31, 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 $15.9 million and $12.9 million, respectively. Refer to Note 15 of the Interim Condensed Consolidated Financial Statements for additional details.

Total operating costs for the first quarter of 2016 were $243 million, which includes the Company's $15.9 million share of income from equity investments in the ODL and Bicentenario pipelines and $25 million ($2.32/boe) in net take-or-pay fees paid to Oleoducto Bicentenario de Colombia S.A.S. ("**Bicentenario**") for non available capacity. When the Bicentenario pipeline was suspended for 47 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 first quarter of 2016, total operating costs were $243 million, a 47% decrease compared to $462 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 $64 million in the first quarter of 2015 to $1 million in the first quarter of 2016, mainly due to lower sales volumes.

Depletion, Depreciation and Amortization

	Three Months Ended March 31	
(in thousands of US$)	2016	2015
Depletion, depreciation and amortization	$ 230,592	$ 406,419
$/per boe sales (own production)	21.08	27.44

For the first quarter of 2016, DD&A costs were $231 million, compared to $406 million for the same period of 2015. The 43% decrease is primarily due to the lower carrying amount of oil & gas properties resulting from the impairments recognized during 2014 and 2015. Unit DD&A for the first quarter 2016 was $21.08/boe, 23% lower than the $27.44/boe for the same period of 2015. During the first quarter 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 March 31	
(in thousands of US$)	2016	2015
Impairment and exploration expenses	$ 666,898	$ 448,967
$/per boe sales (own production)	60.96	30.31

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

As a result of the restructuring being negotiated between the Company and its lenders and Senior note holders, as well as the Restructuring Transaction entered into on April 19, 2016, the Company believed there to be 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. As a result of the test, the Company recorded a total impairment charge of $666.7 million. Details of the impairment are set out as detailed below:

	Three Months ended March 31	
(in thousands of US$)	2016	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	166	112,000
Belize	182	-
Peru	8,763	33,000
Brazil	924	35,000
Papua New Guinea	-	13,000
Other	18	8,000
Total Impairment Impact D&P, PP&E and E&E	**$ 614,051**	**$ 201,000**
Impairment of other assets	52,595	-
Goodwill allocated to Colombia	-	237,009
Total impairment	**$ 666,646**	**$ 438,009**

Total impairment and exploration expenses are summarized below:

	Three Months Ended March 31	
(in thousands of US$)	2016	2015
Impairment	$ 666,646	$ 438,009
Impairment of financial assets	252	10,958
Total	**$ 666,898**	**$ 448,967**

General and Administrative Costs

	Three Months Ended March 31	
(in thousands of US$)	2016	2015
General and administrative costs	$ 33,814	$ 54,905
$/per boe sales	3.08	3.39

General and administrative ("**G&A**") costs decreased to $34 million in the first quarter of 2016 from $55 million in the same period of 2015, mainly due to the adoption of cost optimization initiatives. G&A per boe decreased by $0.31/boe to $3.08/boe from $3.39/boe in the same period of 2015.

Finance Costs and Foreign Exchange

	Three Months Ended March 31	
(in thousands of US$)	2016	2015
Finance costs	$ 68,914	$ 78,858

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 March 31, 2016, finance costs totalled $69 million, lower than $79 million in the same period of 2015.

	Three Months Ended March 31	
(in thousands of US$)	2016	2015
Foreign exchange loss	$ (3,339)	$ (35,780)

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 first quarter of 2016, the COP appreciated against the U.S. dollar by 4.2%, compared with a depreciation of 7.7% during the same period of 2015. Foreign exchange loss for the three months ended March 31, 2016, was $3 million, compared with a loss of $36 million in the same period of 2015.

Income Tax Expense

	Three Months Ended March 31	
(in thousands of US$)	2016	2015
Current income tax	$ (11,494)	$ (18,193)
Deferred income tax	1,546	39,687
Total income tax (recovery) expense	**$ (9,948)**	**$ 21,494**
$ per boe	(0.91)	1.33

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

The Colombian statutory tax rate for the first quarter of 2016 was 40% (2015: 39%), which includes the 25% general income tax rate and the fairness tax ("**CREE**") of 15% (2015: 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 March 31, 2016 and 2015, respectively. The Peruvian income tax rate for Block Z-1 was 22% for the quarters ended March 31, 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 charges in Colombia).
- Corporate expenses that result in tax loss carryforwards; however, no deferred tax assets or recovery has 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 4% during the first quarter of 2016, which resulted in an estimated unrealized deferred income tax recovery of $1.5 million. In comparison, the Company recorded $118 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 7.7%.

Excluding the effect from the above-mentioned foreign exchange fluctuations, the effective tax rate for the Company was (1.1)% for the three months ended March 31, 2016, and 2.9% for the three months ended March 31, 2015.

	Three Months Ended March 31	
(in thousands of US$)	**2016**	**2015**
(Apreciation) depreciation of the COP against the U.S. dollar	(4.0)%	7.7%
Net loss before income tax	(890,994)	(745,970)
Current income tax expense	11,494	18,193
Deferred income tax recovery as reported	(1,546)	(39,687)
Total income tax expense (recovery) as reported	**9,948**	**(21,494)**
Excluding effect from depreciation of COP	-	(117,667)
Total income tax expense (recovery) excluding the above effects	**9,948**	**(139,161)**
Effective tax rate excluding effect of COP depreciation	**(1.1)%**	**18.7%**
Effective tax rate including effect of COP depreciation	**(1.1)%**	**2.9%**

During the first quarter 2016, the Company did not recognize any deferred tax relating to foreign exchange fluctuations; therefore, these fluctuations have not been reflected in the deferred tax calculation.

Current income tax in Colombia totalled $11.5 million in the first quarter of 2016, compared to $18.1 million in the first quarter of 2015. The reduction is mainly attributable to lower taxable revenues resulting from the significant drop in international oil prices.

The 2016 wealth tax paid totalled $25 million. Based on the Company's taxable base, the Company will not make an accrual for future years, pursuant to IAS 37 and IFRIC 21.

Capital Expenditures

(in thousands of US$)	Three Months Ended March 31 2016	2015
Production facilities	$ 4,447	$ 25,651
Exploration activities	532	59,284
Early facilities and others	1,592	387
Development drilling	8,966	120,521
Other projects	3,267	20,191
Total capital expenditures	**$ 18,804**	**$ 226,034**

Capital expenditures during the first quarter of 2016 totalled $19 million, $207 million lower than the $226 million in the first quarter of 2015. A total of $4 million was invested in the expansion and construction of production infrastructure, primarily in Rubiales, Quifa SW, Cubiro, Cravoviejo, La Creciente, Guaduas, Guama, Corcel, Guatiquia, Neiva, Orito, Block 131 and Block Z-1 fields; $1 million went into exploration activities; $2 million went into facilities and others; $9 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 March 31, 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 77% of the Company's outstanding debt.

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

metrics in order to avoid default. For practical purposes, these are checked quarterly over a previous twelve-month 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: (i) a U.S. $500 million debtor-in-possession financing facility and a super priority lien over assets of the Filing Entities to secure the obligations under that facility; and (ii) a U.S. $134 million letter of credit facility and a second priority lien over assets of the Filing Entities to secure the obligations under that facility, all as part of the Restructuring Transaction.

Letters of Credit

As at March 31, 2016, the Company had issued letters of credit and guarantees for exploration and operational commitments for a total of approximately $199 million.

Oil Price-Hedging

In the first quarter of 2016, realized gains from oil price-hedging totalled $162 million on 7.65 MMbbl of notional volume, representing $16.20/bbl in higher crude realized prices during the quarter. The average floor prices for the settled hedges were $51/bbl for WTI sales and $56.09/bbl for BRENT sales. For the three months ended March 31, 2016, cumulative realized gains from oil price hedging amounted to $162 million.

The Company undertook a defensive unwinding strategy that not only strengthened the cash position of the Company but also maximized the cash value of the outstanding hedging portfolio of 5.8 MMbbl worth $116.5 million as of February 2016, as part of the active management of the hedging portfolio.

Outstanding Share Data

Common shares

As at May 2, 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 May 2, 2016, there were no warrants outstanding. A total of 12,363,867 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 May 2, 2016, there were 8,656,468 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

Funds flow provided by operating activities for the first quarter of 2016 totalled $143 million (2015: $170 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.

As at March 31, 2016, the Company had negative working capital of $5,486 million, mainly comprised of $206 million in cash and cash equivalents, $41 million in restricted cash, $372 million in accounts receivable, $33 million in inventory, $155 million in income tax receivable, $5 million in prepaid expenses, $963 million in accounts payable and accrued liabilities, $1 million in income tax payable, $5,320 million in the current portion of long-term debt, $11 million in the current portion of obligations under finance lease, and $3 million in asset retirement obligation.

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 Company currently has a number of tax filings under review by the Colombian tax authority ("**DIAN**").

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 three months ended March 31, 2016, the amounts reassessed, including interest and penalties, are estimated at $63.4 million, of which the Company estimates that $23 million should be assumed by companies that share interests in these contracts. The Company disagrees with the DIAN's reassessment and official appeals have been initiated.

On February 24, 2016, the DIAN released a general ruling to a third party, which concluded that the internal consumption of oil produced does not create an IVA obligation. In addition, on May 11, 2016 the first decision on this claim was issued by the Tribunal accepting our position in the current lawsuit stage. Even though this decision will be reviewed by the high court, this favorable outcome sets a precedent to settle the current dispute regarding IVA in favour of the Company, and as such no provision has been recognized in the interim condensed consolidated financial statement.

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

The DIAN is also reviewing certain income tax deductions with respect to the special tax benefit for qualifying petroleum assets as well as other exploration expenditures. As at March 31, 2016, the DIAN has reassessed $60 million of tax owing, including estimated interest and penalties, with respect to the denied deductions.

As at March 31, 2016, the Company believes that the disagreements with the DIAN related to the denied income tax deductions will be resolved in favour of the Company. No provision with respect to income tax deductions under dispute has been recognized in the interim condensed consolidated financial statements.

Equity tax

Effective January 1, 2015, the Colombian Congress introduced a new wealth tax that is calculated on a taxable base (net equity) in excess of COP $1 billion ($0.4 million) as at January 1 of the applicable taxation year. The applicable rates for January 1, 2016, and 2017 are 1.00% and 0.40%, respectively. Based on the Company's taxable base, the Company has accrued a liability for the 2016 fiscal year. Pursuant to IAS 37 and IFRIC 21, in the current year the Company has not made an accrual for future years. The 2016 wealth tax has been estimated at $26.9 million, and recorded as an expense in the Interim Condensed Consolidated Statement of loss.

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 30 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, 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, upon giving notice to the Company. The Company has not received such notice from Transporte Incorporado. Since October 1, 2016, the Company has received continuous and uninterrupted waivers from Transporte Incorporado of its right to early-terminate the mentioned agreement. Such waivers are in effect as at the date of issuance of this document. The Company continues to pay monthly premiums. No provision has been recognized as of March 31, 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 in July 2016. As part of the expansion project, the Company entered into separate crude oil transport agreements with OCENSA for future transport capacity through its subsidiaries Meta Petroleum and Petrominerales Colombia. The Company will start paying ship-or-pay fees once the expansion project is complete and operational. The Company is required to maintain minimum credit ratings of BB- (Fitch) and Ba3 (Moody's) as part of the transport agreements. 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 that will expire once the project is complete and operational. No provision has been recognized as of March 31, 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) During the three months ended March 31, 2016, the Company received cash of $12 million 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 $1 million under the joint operation agreement from Alfa SAB de CV ("**Alfa**") who owns a 51% working capital interest in Block Z-1 and also holds 19.2% of the issued and outstanding capital of the Company.

b) 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 in 2016, the Company's obligations, along with the power generation assets, will be transferred to Ecopetrol. During the three months ended March 31, 2016, those assets were under construction and the Company paid $Nil (2015: $7.1 million) under the Rubiales Association Contract. As at March 31, 2016, the Company had an advance of $Nil (December 2015: $3.3 million).

   The Company had accounts payable of $3.4 million (December 2015: $3.6 million) due to Genser-Proelectrica as at March 31, 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 months ended March 31, 2016, the Company made payments of $6.1 million (2015: $13 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 months ended March 31, 2016, the Company recorded revenues of $5.9 million (2015: $0.7 million) from such agreements. As at March 31, 2016, the Company had trade accounts receivable of $6 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.

c) As at March 31, 2016, the Company had trade accounts receivable of $6 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**"). 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 $5.9 million for the three months ended March 31, 2016 (2015: $0.7 million). Two directors and an officer of the Company (Serafino Iacono, Miguel de la Campa, and Laureano von Siegmund), along with Jose Francisco Arata, a director until August 14, 2015, control or provide investment advice to the holders of approximately 88% of the shares of Blue Pacific.

d) As at March 31, 2016, loans receivable from related parties in the aggregate amount of $0.5 million (December 31, 2015: $0.5 million) are due from one executive director (Serafino Iacono) and seven 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 one of its officers (Jose Francisco Arata), who retired from the Company on August 14, 2015. The payment 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 in June 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.

e) The Company has take-or-pay contracts with ODL for the transportation of crude oil from the Rubiales field to Colombia's oil transportation system for a total commitment of $125 million from 2016 to 2020. During the three months ended March 31, 2016, the Company paid $29.6 million to ODL (2015: $34.4 million) for crude oil transport services under the pipeline take-or-pay agreement and had accounts payable of $10 million (December 31, 2015: $13.1 million). In addition, the Company received $0.1 million from ODL during the three months ended March 31, 2016 (2015: $0.4 million) with respect to certain administrative services and rental equipment and machinery. The Company had accounts receivable from ODL as at March 31, 2016 of $0.1 million (December 31, 2015: $0.1 million). The Company has an approximately 22% indirect interest in ODL.

f) The Company has ship-or-pay contracts with Bicentenario for the transportation of crude oil from the Rubiales field to Colombia's oil transportation system for a total commitment of $1.5 billion from 2016 to 2025. The Bicentenario pipeline has experienced periodic suspensions following security-related disruptions. During the three months ended March 31, 2016, the Company paid $50.3 million to Oleoducto Bicentenario de Colombia S.A.S. (2015: $27.9 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 March 31, 2016, the balance of loans outstanding to Bicentenario was $Nil (December 31, 2015: $Nil). Interest income of $Nil was recognized during the three months ended March 31, 2016 (2015: $0.6 million). Interest of $Nil was paid on the loans during the three months ended March 31, 2016 (2015: $1.3 million), and capital of $Nil was paid on the loans in the three months ended in March 31, 2016 (2015: $17.2 million). The Company has advanced $87.9 million as at March 31, 2016 (2015: $87.9 million) to Bicentenario as a prepayment of transport tariff, which is amortized against the barrels transported. As at March 31, 2016, the Company had trade accounts receivable of $13.5 million (December 31, 2015: $0.4 million) as a short-term advance.

g) 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 months ended March 31, 2016, the Company contributed $3.6 million to these foundations (2015: $2.5 million). At as March 31, 2016, the Company had accounts receivable (advances) of $0.9 million (December 31, 2015: $0.4 million) and accounts payable of $0.5 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.

h) At as March 31, 2016, the Company had demand loans receivable from PII in the amount of $72.4 million (December 31, 2014: $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 41.79% of PII. Interest income of $1.3 million was recognized during the three months ended March 31, 2016 (2015: $1.2 million) regarding to the loan. In addition, during the three months ended March 31, 2016, the Company received $2.1 million (2015: $Nil) from PII with respect to contract fees for advisory services and technical assistance in pipeline construction of "Oleoducto del Caribe." In addition, as at March 31, 2016, the Company had accounts receivable of $2.4 million (December 31, 2015: $0.5 million) from Pacific Infrastructure Ventures Inc., a branch of PII. As at March 31, 2016, the Company had accounts payable of $0.7 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.

i) In October 2012, the Company entered into an agreement with Caribbean Resources Coporation (previously Pacific Coal Resources Ltd.) ("**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 8.49% equity interest in CRC. In addition, the Company has an indirect equity interest of 8.61% in CRC through its 21.1% ownership of Pacific Power, which in turn has a 40.86% equity interest in CRC. Hernan Martinez, a director of the Company, is the Executive Chairman of CRC.

j) 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).

k) On February 29, 2016, the Company agreed to provide CGX Energy Inc. ("**CGX**") with a bridge loan of up to $2 million at an interest rate of 2% per annum and payable within 12 months of the first draw down. As at March 31, 2016, the amount CGX had drawn down from the bridge loan was $Nil.

In October 2014, the Company extended a bridge loan to CGX of $7.5 million Canadian dollars with an interest rate of 5%, as at March 31, 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 $0.335 Canadian dollars, as at March 31, 2016 the Company has not converted the debentures.

8 Selected Quarterly Information

	2016	2015				2014				2013
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Financials:										
Net sales	$ 456,831	$ 651,970	$ 669,995	$ 702,733	$ 799,848	$ 991,508	$ 1,330,395	$ 1,344,666	$ 1,283,453	$ 1,202,551
Net (loss) earnings attributable to equity holders of the parent for the period	(900,949)	(3,895,908)	(617,318)	(226,377)	(722,256)	(1,660,876)	3,484	228,527	119,240	140,412
(Loss) Earnings per share										
- basic	(2.86)	(12.37)	(1.97)	(0.72)	(2.31)	(5.26)	0.01	0.73	0.38	0.43
- diluted	(2.86)	(12.37)	(1.97)	(0.72)	(2.31)	(5.26)	0.01	0.72	0.37	0.43

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 March 31, 2016 and 2015 have been prepared in accordance with International Financial Reporting Standards ("**IFRS**") as issued by International Accounting Standards Board ("**IASB**"), including the accounting policies and critical judgments and estimates as disclosed in Note 2 of the Interim Condensed Consolidated Financial Statements.

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

For the three months ended March 31, 2016, the Company incurred a net loss of $900.9 million and had a deficit of $3,867 million as of March 31, 2016, primarily due to impairment charges recorded.

Since late 2014, the Company has implemented a number of cost reduction initiatives in response to the prevailing low crude oil prices, including:

- Significantly reduced operating and general and administrative expenses;
- Lowered the 2016 capital expenditure budget;
- Engaged in ongoing debt restructuring negotiations; and
- Continued negotiations on non-core asset sales.

Despite the above initiatives, at current crude oil prices, the Company will likely need new financing to fund its interest payments and debt repayments as they become due, and possibly operating cash needs. The Company currently has forbearance agreements in place with certain holders of its senior notes and revolving and bank credit facilities, whereby the credit parties under these agreements have agreed to forbear from declaring the principal amounts due and payable as a result of certain specified defaults until March 31, 2016. The Company continues to engage with creditors on restructuring the capital structure to be more suitable to current market conditions.

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 of the Interim Condensed Consolidated Financial Statements).

There can be no certainty as to the ability of the Company to successfully restructure its long-term debts under the Restructuring Transaction and amend the applicable operating agreements to eliminate the credit rating covenants. Accordingly, there is a material uncertainty that may cast doubt on the Company's ability to continue as a going concern. The Interim Condensed Consolidated 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 the interim condensed 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 January 1, 2016, with early adoption permitted. These amendments do not have any impact on the Company as there has been no interest acquired in a joint operation during the period.

IAS 34 Interim Financial Reporting

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

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.

Hedge accounting

Hedge effectiveness testing is prospective, without the 80% to 125% bright line test in IAS 39, and depending on the hedge complexity, will often qualitative. A risk component of a financial or non-financial instrument may be designated as the hedged item if the risk component is separately identifiable and reliably measureable. The time value of an option, any forward element of a forward contract and any foreign currency basis spread can be excluded from the hedging instrument designation and can be accounted for as costs of hedging. More designations of groups of items as the hedged item are possible, including layer designations and some net positions.

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.

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 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 first quarter of 2016, 133 controls were tested over the 687 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 March 31, 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 March 31, 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 March 31, 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 the ANH once an exploitation area within a contracted area has cumulatively produced five million or more barrels of oil. The disagreement involves whether the exploitation areas under these contracts should be determined individually or combined with other exploration areas within the same contracted area, for the purpose of determining the five million barrel threshold. The ANH has interpreted that the high-price participation should be calculated on a combined basis.

The Company disagrees with the ANH's interpretation and asserts that, in accordance with the exploration contracts, the five million barrel threshold should be applied on each of the exploitation areas within a contracted area. The Company has several contracts that are subject to ANH high-price participation. One of these contracts is the Corcel Block, which was acquired as part of the Petrominerales acquisition and is the only one for which an arbitration process has been initiated. However, the arbitration process for Corcel was under suspension at the time the Company acquired Petrominerales. As at March 31, 2016, the amount under arbitration is approximately $194 million, plus related interest of $39 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, although 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

On February 29, 2016, the Autoridad Nacional de Licencias Ambientales ("**ANLA**") granted the disposal of produced water from Quifa in Rubiales field, authorizing the reuse of this water for agricultural purposes.

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 March 31	
(in thousands of US$)	**2016**	**2015**
Net loss [(1)]	**$ (900,949)**	**$ (722,256)**
Adjustments to net loss		
Income tax expense (recovery)	9,948	(21,494)
Foreign exchange loss	3,339	35,780
Finance cost	68,914	78,858
Loss on risk management contracts	113,545	167
Gain of equity-accounted investees	(26,847)	(17,453)
Other (income) expenses	(42,210)	21,570
Share-based compensation	(3,206)	2,086
Equity tax	26,901	39,149
Gain (Loss) attributable to non-controlling interest	7	(2,220)
Depletion, depreciation and amortization	230,592	406,419
Impairment and exploration expenses	666,898	448,967
Restructuring Costs	16,780	-
Adjusted EBITDA	**$ 163,712**	**$ 269,573**

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

Funds Flow from Operations

	Three Months Ended March 31	
(in thousands of US$)	**2016**	**2015**
Cash flow from operating activities	$ (35,726)	$ 98,946
Changes in non-cash working capital	103,828	271,003
Deferred revenue net proceeds	75,000	(199,475)
Funds flow from operations	**$ 143,102**	**$ 170,474**

Net Loss from Operations

(in thousands of US$)	Three Months Ended March 31 2016	2015
Net loss [(1)]	**$ (900,949)**	**$ (722,256)**
Finance costs	68,914	78,858
Gain of equity-accounted investees	(26,847)	(17,453)
Equity tax	26,901	39,149
Foreign exchange loss	3,339	35,780
Loss on risk management contracts	113,545	167
Other (income) expenses	(42,210)	21,570
Income tax expense (recovery)	9,948	(21,494)
Gain (loss) attributable to non-controlling interest	7	(2,220)
Net loss from operations	**$ (747,352)**	**$ (587,899)**

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

Engagement with indigenous communities

During March 2016, the Company was formally notified of the Colombian Constitutional Court's decision instructing the Company to suspend operations within two kilometres of the border of an indigenous community known as “Vencedor Piriri” encompassing a portion of Quifa Block. Operations in this area are to be suspended until a prior consultation process is conducted with the indigenous community.

In the past, the Company has demonstrated that it has effectively met consultation process requirements in locations identified by the Ministry of Interior, pursuant to Colombian law. However, the Constitutional Court ruled that it should conduct a prior consultation process in an area that to the best of the Company's knowledge, as well as pursuant to official certifications by the Colombian Ministry of Interior, does not have the presence of an indigenous community. The Constitutional Court alleges indirect damages to the indigenous community in the two kilometre border area.

After the notification, the Company proceeded to develop and file a plan for operational suspension in the 2-km radius of the indigenous reservoir with the applicable Colombian authorities. The Company has initiated the fulfillment of the mandate of prior consultation in the area in question. It is important to add we have implemented contingency plans so as to not materially affect the production from the Quifa Block and expect the suspension period to last for approximately ten weeks.

EITI (Extractive Industries Transparency Initiative)

As reported in the fourth quarter of 2015, the company participated in the preparation of the first EITI report at the country level for Colombia. The report made public the taxes, royalties and contributions made by 18 oil and gas companies during the 2013 fiscal year, amounting to over $17 billion. One of the purposes of the report is to compare what the companies report they have paid to what government entities report they have received. Pacific´s contribution to the exercise is summed up as follows: between 30-40% of taxes received by the DIAN were paid by Pacific. Cash royalties paid by Pacific accounted for 12% of the total, while in-kind royalty payments in the form of barrels accounted for almost 60% of the total received by state agencies, ANH and Ecopetrol. This is an important exercise of transparency and accountability that raises awareness within the society of the oil and gas industry, contributing to its legitimization. Additionally, we participated in the global forum EITI in Peru reaffirming our commitment to the initiative worldwide.

Sustainability report highlights

During May 2016, the Company plans to publish its seventh sustainability report. In this report, we will disclose the performance of our sustainability model and our accomplishments for the year end 2015.

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 will likely need 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: (i) a U.S. $500 million debtor-in-possession financing facility and a super priority lien over assets of the Filing Entities to secure the obligations under that facility; and (ii) a U.S. $134 million letter of credit facility and a second priority lien over assets of the Filing Entities to secure the obligations under that facility, 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, amend the applicable operating agreements to eliminate the credit rating covenants, and obtain new 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.

The Company intends to fund its anticipated cash requirements through the end of 2016 primarily through cash on hand 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 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. The urgency of the Company's liquidity constraints may require the Company to pursue such transactions at an inopportune time. Moreover, the Company's ability to successfully implement, and the cost of, any such transactions 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 renew the forbearance or extension agreements with respect to the Credit Facilities and the 2109 Senior Notes and 2025 Senior Notes, as applicable;
- 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.

If the Company is unable to continue as a going concern, it would likely need to seek relief under applicable bankruptcy and insolvency legislation, which may negatively affect the price and volatility of the Company's common shares and other securities of the Company and any investment in such shares or securities could suffer a significant decline or total loss in value.

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

- Volatility in market prices for oil and natural gas;
- A continued depressed oil price environment with the potential of further decline;
- Default under the credit facilities and/or senior notes due to a breach of covenants therein;
- Early termination of one or more of the Lender Forbearance Agreements and/or the Noteholder Extension Agreement;
- Amounts becoming due and payable under the credit facilities or senior notes, notwithstanding the entering into of the Lender Forbearance Agreements and the Extension Agreement, whether through the actions of holders of the 2019 Senior Notes and 2025 Senior Notes or the trustee under each respective indenture or otherwise;
- The impact of events of defaults in respect of the credit facilities, 2019 Senior Notes and 2025 Senior Notes on other material contracts of the Company, including but not limited to, cross-defaults resulting in acceleration of amounts payable thereunder or the termination of such agreements;
- Failure of the Company to reach an agreement with its creditors to restructure the Company's capital structure;
- Failure to satisfy any terms or conditions of any agreement with its creditors on a proposed restructuring;
- Any negative impact on the Company's current operations as a result of any proposed restructuring or failure to reach an agreement with the creditors thereon;
- Failure to satisfy the terms and conditions of any one of the Company's waiver agreements with applicable creditors or any other waiver, failure to obtain further extensions of any such waivers, or failure to obtain waivers of other covenants, if and when required;
- The terms of any waivers, including the impact on the Company of any restrictions imposed upon it in connection with any waiver;
- Failure to obtain additional financial resources to avoid the need to seek relief under the bankruptcy and insolvency laws in one or more jurisdictions of Canada, the United States, Colombia and/or other jurisdictions (or avoid an involuntary petition for bankruptcy relief or similar creditor action filed against the Company);
- 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 continue meeting the listing requirements of the exchanges on which the Company's securities are listed;
- The value of the Company's equity securities being reduced to zero as a result of an insolvency filing and that such proceedings may ultimately result in the cancellation of the Company's equity securities;
- 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 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, filed on March 18, 2016, and 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