MANAGEMENT DISCUSSION & ANALYSIS

May 5, 2017

For the three months ended March 31, 2017

CONTENTS

Legal Notice – Forward-Looking Information and Statements

Certain statements in this Management's 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" on page 24. 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 14, 2017, 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, 2017 and 2016. 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, 2017 and 2016, 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 14.

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

1. Message to the Shareholders

Pacific is off to a great start and is positioned to perform well in 2017, a critical year, as the Company shifts focus and resources towards sustainable production through development drilling and growth through low-risk exploration. Our efforts to maximize the value of non-E&P related assets and reduce overall costs are evident in this quarter's results. Pacific's goal is to improve margins and drive higher returns for invested capital.

During the first quarter of 2017, net production after royalties and internal consumption totalled 72,524 boe/d, compared with 69,432 boe/d in the fourth quarter of 2016, representing an increase of 4% quarter over quarter. Heavy oil production from Quifa SW and other fields increased by 12% in the quarter in comparison with the fourth quarter of 2016. The increase in heavy oil production was slightly offset by a reduction in light and medium oil and gas production in Colombia that totalled 40,665 bbl/d, a decrease of 4% compared with the fourth quarter of 2016. During the first quarter of 2017, 26 development wells were drilled in the Quifa SW, CPE-6, Cubiro, Guatiquia, and Orito fields. On January 31, 2017, Block 192 in Peru reactivated operations, allowing a ramp-up of production.

First quarter revenue increased to $316.6 million from $269.8 million in the fourth quarter of 2016, due to the nearly 9% year-on-year increase in realized crude oil prices and increased production at the Company's heavy oil fields. The Company has actively engaged in building new hedging positions, progressively closing volumes of up to 1.4 million barrels of oil per month up to November 2017, to continue protecting cash flows from a potential downturn in the price of oil.

During the first quarter of 2017, net income attributable to equity holders of the parent was $8.5 million compared with a net loss of $900.9 million in the same period last year, as a result of lower gross earnings due mainly to the Rubiales-Piriri contract expiration offset by lower depletion, depreciation and amortization and the impairment reversal recognized during the first quarter of 2017. Operating EBITDA was $92.4 million for the first quarter of 2017, higher than the $44.3 million achieved in the fourth quarter of 2016 due to higher realized prices and volumes sold (for a discussion on Operating EBITDA and other Non-IFRS measures, please refer to page 15). General and Administrative costs (excluding restructuring and severance expenses) decreased to $27.7 million in the first quarter of 2017 from $39.6 million in the fourth quarter of 2016 and $32.9 million in the first quarter of 2016, mainly due to continuing efforts to minimize discretionary spending and ongoing headcount reductions.

The Company continues to negotiate field commitments to focus on high impact development drilling, while reviewing the broad set of upstream and midstream assets within the Company's portfolio with an emphasis on value-maximizing initiatives, reducing its commitments by $67.6 million during 2017. The first quarter of 2017 is a clear indication that everyone at Pacific is making the necessary adjustments to improve the Company's operational and financial performance.

"Barry Larson"
Chief Executive Officer

2. Results for the Three Months Ended March 31, 2017

Financial and Operating Summary

(in thousands of US$ except per share amount or as noted)	Q1 2017	Q4 2016	Q1 2016
Operating activities			
Average sales volumes (boe/d)	76,256	69,653	120,567
Average oil and gas sales (boe/d)	70,452	67,470	120,220
Oil sales (bbl/d)	64,350	60,735	110,010
Gas sales (boe/d)	6,122	6,738	10,210
Overlift (boe/d)	(20)	(3)	-
Average trading sales (bbl/d)	5,804	2,183	347
Average net production (boe/d)	72,524	69,432	142,337
Average net production oil (bbl/d)	66,035	62,229	131,856
Average net production gas (boe/d)	6,489	7,203	10,481
Average net production (boe/d) (excluding Rubiales field)	72,524	69,432	92,851
Combined price ($/boe)	45.95	41.92	41.67
Realized oil and gas price ($/boe)	47.34	43.44	26.90
Realized hedging (loss) gain ($/boe)	(1.39)	(1.52)	14.77
Operating cost ($/boe)	(25.91)	(27.98)	(21.35)
Operating netback crude oil and gas ($/boe) [1]	20.04	13.94	20.32
Consolidated netback ($/boe) [1]	17.89	13.30	19.58
Cash netback ($/boe) [1]	12.57	5.46	11.46
Capital expenditures	37,578	64,248	18,804
Financials			
Total sales ($)	316,638	269,772	456,831
Net crude oil and gas sales and other income	285,020	260,235	455,835
Trading	25,271	9,593	915
Overlift (underlift)	6,347	(56)	81
Net income (loss) [2]	8,498	4,025,194	(900,949)
Per share - basic ($) [3]	0.17	80.50	(285,996.31)
Operating EBITDA [1]	92,442	44,275	190,064
Operating EBITDA margin (Operating EBITDA/revenues)	29%	16%	42%
Consolidated EBITDA [1]	115,057	(1,967)	91,814
Consolidated EBITDA margin (Consolidated EBITDA/revenues)	36%	(1)%	20%
Total Assets ($)	2,772,423	2,741,719	2,687,858
Total Equity (Deficit) ($)	1,516,983	1,495,770	(3,986,755)
Debt and obligations under finance lease ($)	272,087	272,942	5,352,319

1. *Refer to Non-IFRS measures on page 15.*
2. *Net income (loss) attributable to equity holders of the parent.*
3. *The basic and diluted weighted average numbers of common shares for the three months ended March 31, 2017 were 50,002,363 and 50,025,751, respectively.*

Results

Operational

- Net production after royalties and internal consumption in the first quarter totalled 72,524 boe/d, representing a 4% increase compared with the fourth quarter of 2016. Drilling reactivation at the Company's heavy oil fields and incremental production from Block 192 in Peru were the main drivers for increased production in the quarter.
- Total operating costs, including production, transportation, and diluent costs, were at the lower end of the Company's guidance, decreasing from $27.98/boe in the fourth quarter of 2016 to $25.91/boe in the first quarter of 2017. The reduction was mainly attributable to higher produced volumes and lower production costs, which decreased from $79.0 million in the fourth quarter of 2016 to $67.4 million in the first quarter of 2017.
- In February 2017, the Bicentenario pipeline decreased its transportation tariff from $8.54/bbl to $7.56/bbl.
- On January 31, 2017, Block 192 in Peru reactivated operations, allowing the ramp-up of production.
- On February 22, 2017, the Company received a letter from Perupetro finalizing the Block 135 contract, with an effective date of March 13, 2017, reducing its exploration commitments by $15.0 million.
- On April 3, 2017, the Company requested that the ANH approve the transfer of $6.0 million in investment commitment from the CPO-12 Block to two exploratory wells in the CPE-6 Block. The Company continues to negotiate field commitments to focus on high-impact development drilling.

Assets Held for Sales

Q1 update	Assets	Country	Buyer	Net Cash Consideration	Enviromental Liabilities (*)	Exploration Obligations (*)	Bank Guarantees	Status
Closed	Karoon blocks	Brazil	Karoon	$ 15.5	$ -	$ 50.8	$ -	Cash received
Closed	Queiroz blocks	Brazil	Queiroz	(10.0)	-	25.6	42.5	Pending cash
Signed	Putumayo Basin	Colombia	Amerisur	4.8	0.2	26.1	2.9	Pending Governmental approval
Signed	Casanare Este	Colombia	Gold Oil	0.2	4.1	7.9	0.8	Pending Governmental approval; 50% of cash received
In progress	Lot 126	Peru	Maple Gas	0.2	TBD	3.6	2.8	Cash received; under negotiation final terms
In progress	Lot 131	Peru	Cepsa	17.8	1.6	7.2	-	Pending final Governmental approval
Q2 deal	San Jacinto 7 block	Colombia	CNE Oil	Nominal	-	7.8	2.5	Pending Governmental approval
				$ 28.5	**$ 5.9**	**$ 129.0**	**$ 51.5**	

** Estimated*

- On March 10, 2017, the Company and Amerisur Exploración Colombia Limitada ("**Amerisur**") entered into four farm-out agreements pursuant to which Amerisur agreed to acquire the following participating interests in certain of the Company's exploration and production of hydrocarbons contracts (collectively, the "**Participating Interests**"): (i) 60% participating interest in the PUT-9 Block; (ii) 50.5% participating interest in the Tacacho Block; (iii) 58% participating interest in the Mecaya Block; and (iv) 100% participating interest in the Terecay Block. The aggregate purchase price for the Participating Interests was $4.9 million, plus a royalty calculated and payable on a monthly basis equal to 2% of all the hydrocarbons produced in the Terecay Block, and a royalty calculated and payable on a monthly basis equal to 1.2% of all the hydrocarbons produced in the PUT-9 Block, subject to certain terms and conditions. Each farm-out agreement is subject to approval by Agencia Nacional de Hidrocarburos ("**ANH**"). Upon closing of the transaction, the Company will have reduced its exploration commitments related to these blocks by approximately $26.1 million.
- On March 13, 2017, the Company entered into a binding term sheet with Maple Gas Corporation del Peru SRL ("**Maple**") pursuant to which the Company has agreed to transfer its participating interest in Lot 126 for $0.2 million and, the assumption of contractual exploration obligations by $3.6 million.
- On March 30, 2017, the Company executed a farm-out agreement with Gold Oil PLC Sucursal Colombia ("**Gold Oil**") for the transfer of its participating interest and operatorship in the Casanare Este Block for $0.2 million. The farm-out agreement is subject to ANH approval. Upon closing of the transaction, the Company will have reduced its exploration commitments related to this block by $7.9 million.
- On April 25, 2017, the Company and CNE Oil & Gas S.A.S., a subsidiary of Canacol Energy Ltd., ("**CNE Oil**") entered into a farm-out agreement whereby CNE Oil agreed to acquire the Company's participating interest in the San Jacinto 7 Block, in consideration for assuming all contractual exploration obligations by $7.8 million. The agreement is subject to approval by the ANH.

- On April 26, 2017, the Company and Cepsa Peruana S.A.C. ("**Cepsa**") received Peruvian regulatory approval for the farm-out agreement whereby Cepsa agreed to acquire the Company's participation interest in one onshore block in Peru, Lot 131, for a total cash consideration of $17.8 million and the assumption of contractual exploration obligations of $7.2 million.

Financial

- Revenue increased to $316.6 million from $269.8 million in the fourth quarter of 2016 due to the higher volumes sold during the quarter. The Company's average sales price per barrel of crude oil and natural gas was $45.95/boe, up from $41.92/boe in the fourth quarter of 2016. Revenue decreased by $140.2 million in comparison with the first quarter of 2016 mainly due to the Rubiales-Piriri contract expiration and volumes sold.
- Combined oil and gas Operating Netback for the first quarter of 2017 was $20.04/boe, 44% higher than the $13.94/boe in the fourth quarter of 2016, mainly attributable to higher realized sale prices, higher production volumes sold, and lower operating costs.
- Operating EBITDA was $92.4 million for the first quarter of 2017, higher compared with $44.3 million in the fourth quarter of 2016 due to higher realized prices and volumes sold. In comparison with the first quarter of 2016, Operating EBITDA was lower by $97.6 million, primarily due to the expiration of the Rubiales-Piriri contract in June.
- General and administrative ("**G&A**") costs (excluding restructuring and severance expenses) decreased to $27.7 million in the first quarter of 2017 from $39.6 million and $32.9 million in the fourth and first quarter of 2016, respectively. The Company continues to reduce G&A and all non-essential spending activities. A majority of the reduction is complete; however, the Company will continue to look for additional streamlining and optimization opportunities to eliminate unnecessary costs.
- During the first quarter of 2017, net income attributable to equity holders of the parent was $8.5 million compared with a net loss of $900.9 million in the same period last year, as a result of lower gross earnings due mainly to the Rubiales-Piriri contract expiration offset by lower depletion, depreciation and amortization and the impairment reversal recognized during the first quarter of 2017.
- Total capital expenditures decreased to $37.6 million in the first quarter of 2017 compared with $64.2 million for the fourth quarter of 2016.

Restructuring Transaction

On April 19, 2016, the Company, with the support of certain holders of its senior unsecured notes and lenders under its credit facilities, which totalled $5.3 billion, entered into an agreement with The Catalyst Capital Group Inc. ("**Catalyst**") with respect to a comprehensive financial Restructuring Transaction (the "**Restructuring Transaction**"). Under the terms of the Agreement, the claims were exchanged for new common shares of the Company post-emergence. In addition, during the restructuring transaction, Catalyst and certain affected creditors provided $480.0 million of debtor-in-possession financing to improve liquidity of the Company. On November 2, 2016, the Company successfully completed the Restructuring Transaction upon approval of the CCAA plan of arrangement by the Superior Court of Justice in Ontario. The Restructuring Transaction substantially changed the capital structure of the Company, reducing financial debt to $250.0 million, which is represented in five-year secured notes (the "**Exit Notes**") and a Letter of Credit Facility which at the time of the Restructuring Transaction totalled $115.5 million; after completion of the restructuring transaction, the shareholders of the Company are the affected creditors with 69.2% and Catalyst with 30.8% of the common shares.

Additional information is included in Note 1: Comprehensive Restructuring Transaction of the Company's annual financial statements as at December 31, 2016.

Principal Properties

	Working interest	Operated	Gross Acres	Net Acres
Colombia Central				
Quifa	60.00%	Operated	265,954	159,572
Guatiquia	100.00%	Operated	14,372	14,372
Cubiro	100.00%	Operated	44,360	44,360
Cravo Viejo	100.00%	Operated	46,839	46,839
Casimena	100.00%	Operated	32,188	32,188
Arrendajo	97.50%	Operated	33,280	32,448
Neiva	55.60%	Non-operated	2,395	1,332
Corcel	100.00%	Operated	25,141	25,141
Cachicamo	100.00%	Operated	28,471	28,471
Canaguaro	87.50%	Operated	6,289	5,503
Dindal - Rio Seco	45.00%	Operated	47,689	21,539
Sabanero	100.00%	Operated	87,540	87,540
Llanos 7	100.00%	Operated	152,674	152,674
Llanos 55	100.00%	Operated	101,466	101,466
Llanos 83	100.00%	Operated	35,755	35,755
Llanos 25	100.00%	Operated	169,805	169,805
Casanare Este (1)	100.00%	Operated	18,476	18,476
Rio Ariari	100.00%	Operated	307,036	307,036
Mapache	100.00%	Operated	55,374	55,374
CPE-6	100.00%	Operated	593,018	593,018
CPO-12	57.00%	Operated	708,765	404,988
CPO-14	63.00%	Operated	517,656	323,535
Abanico	25.00%	Operated	62,560	15,640
Buganvilles	49.00%	Operated	77,754	38,100
Cordillera-24	85.00%	Operated	619,817	526,844
CPO-17 (2)	25.00%	Non-operated	519,663	129,916
Cordillera-15 (2)	50.00%	Non-operated	294,935	147,468
Muisca (2)	50.00%	Non-operated	585,126	292,563
Colombia North				
La Creciente	100.00%	Operated	26,650	26,650
Guama	100.00%	Operated	70,993	70,993
SSJN-3	100.00%	Operated	634,364	634,364
SSJN-7 (3)	50.00%	Operated	668,919	334,460
CR-1	60.00%	Operated	307,384	184,431
Cerrito	80.00%	Non-operated	10,166	8,112
Colombia South				
Orito	79.00%	Non-operated	42,492	33,569
Caguan-5	50.00%	Operated	919,321	459,661
Caguan-6	60.00%	Operated	119,048	71,429
Portofino	40.00%	Non-operated	258,676	103,470
Tinigua	50.00%	Non-operated	105,467	52,734
Terecay (4)	100.00%	Operated	586,626	586,626
Tacacho (4)	50.50%	Operated	589,008	297,449
Putumayo-9 (4)	60.00%	Operated	121,452	72,871
Mecaya (4)	58.00%	Operated	74,127	42,993
Peru				
Block Z1	49.00%	Operated	554,443	271,677
Lot 131 (5)	30.00%	Non-operated	1,923,476	577,043
Lot 126 (6)	100.00%	Operated	1,048,762	1,048,762
Lot 116	50.00%	Operated	1,628,126	814,063
Lot 192	84.00%	Operated	1,266,037	1,266,037

1. *Blocks held for sale; please refer to Gold Oil operational highlight on page 3.*
2. *Includes investment on Maurel & Prom Colombia B.V. fields.*
3. *Blocks held for sale; please refer to CNE Oil operational highlight on page 3.*
4. *Blocks held for sale; please refer to Amerisur operational highlight on page 3.*
5. *Blocks held for sale; please refer to Cepsa operational highlight on page 4.*
6. *Peru block held for sale; please refer to Maple operational highlight on page 3.*

3. Financial and Operational Results

Netbacks

The Company's netbacks are summarized below. For discussion on the definitions of how the Company uses Operating Netback, Consolidated Netback, and Cash Netback, please refer to Non-IFRS Financial Measures on page 16 in the Financial and Operational Results section.

	Q1 2017	Q4 2016	Q1 2016	For reconciliation to IFRS figures, see section:
Average daily D&P production volume (boe/d)	**70,992**	**68,011**	**140,911**	D&P Production pg. 7
Combined Operating Netback ($/boe)				
ICE BRENT price	54.57	51.06	35.21	
Hedge effect	(1.39)	(1.52)	14.77	
Differential	(7.23)	(7.62)	(8.31)	
Crude oil and natural gas sales price	**45.95**	**41.92**	**41.67**	Sales pg. 9
Production cost of barrels	(10.55)	(12.63)	(7.56)	
Transportation (trucking and pipeline)	(14.28)	(14.82)	(11.76)	
Diluent cost	(1.08)	(0.53)	(2.03)	
Total Operating cost	**(25.91)**	**(27.98)**	(21.35)	Operating costs pg. 10
Operating netback crude oil and gas ($/boe)	**20.04**	**13.94**	**20.32**	
Fees paid on suspended pipeline capacity	(4.24)	(2.98)	(1.98)	Operating costs pg. 10
Share of gain of equity-accounted investees - pipelines	2.09	2.34	1.24	Equity investees pg. 12
Consolidated netback ($/boe)	**17.89**	**13.30**	**19.58**	
General and administrative expenses	(4.34)	(6.34)	(2.56)	G&A pg. 12
Cash finance costs	(0.98)	(1.50)	(5.56)	Finance costs pg. 12
Cash netback ($/boe)	**12.57**	**5.46**	**11.46**	

During the three months ended March 31, 2017 the Company's crude oil and natural gas sales price from operated barrels increased to $45.95/boe from $41.92/boe in the fourth quarter of 2016 and $41.67/boe in the first quarter of 2016, due to improvements in world crude prices.

Total operating costs, including production, transportation, and diluent costs, decreased from $27.98/boe in the fourth quarter of 2016 to $25.91/boe in the first quarter of 2017. The reduction was mainly attributable to higher produced volumes, lower production costs, and the reactivation of Block 192 in Peru on January 31, 2017.

During the first quarter of 2017, the Bicentenario pipeline was not operational for 50 days; the Company was able to source available operational capacity from the OCENSA pipeline at comparable costs per unit. The cost redundancy from unused pipeline take-or-pays impacted consolidated netback by $4.24/bbl.

Production and Development Review

The following table highlights the average daily total gross and net share production after royalties from all of the Company's producing fields in Colombia and Peru, reconciled to volume sold.

	Average Quarter Production (in boe/d)						
	Total field production		Gross share before royalties [1]		Net share after royalties		
Producing fields in Colombia	**Q1 2017**	**Q1 2016**	**Q1 2017**	**Q1 2016**	**Q1 2017**	**Q4 2016**	**Q1 2016**
Rubiales / Piriri	-	149,639	-	61,857	-	-	49,486
Quifa SW [2]	46,158	51,486	27,501	30,419	25,007	22,135	27,551
	46,158	**201,125**	**27,501**	**92,276**	**25,007**	**22,135**	**77,037**
Other fields in Colombia							
Light and medium [3]	39,054	50,205	37,161	47,453	34,177	35,182	45,202
Gas [4]	7,468	11,486	6,489	10,481	6,489	7,203	10,481
Heavy oil [5]	4,085	4,868	3,116	3,692	2,996	2,833	3,533
	50,607	**66,559**	**46,766**	**61,626**	**43,662**	**45,218**	**59,216**
Total production Colombia	**96,765**	**267,684**	**74,267**	**153,902**	**68,669**	**67,353**	**136,253**
Producing fields in Peru							
Light and medium [6]	7,805	9,928	3,855	6,084	3,855	2,079	6,084
	7,805	**9,928**	**3,855**	**6,084**	**3,855**	**2,079**	**6,084**
Total production Colombia and Peru	**104,570**	**277,612**	**78,122**	**159,986**	**72,524**	**69,432**	**142,337**
Total production excluding Rubiales/Piriri	**104,570**	**127,973**	**78,122**	**98,129**	**72,524**	**69,432**	**92,851**

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 and Cajua fields 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. Subject to approval from the ANH, the Company is in the process of divesting its participation in Casanare Este.*
4. *Mainly includes La Creciente and other fields.*
5. *Includes Cajua, Sabanero, CPE-6, Rio Ariari, Prospecto S, and Prospecto D fields.*
6. *Includes Block Z1, Block 131, and Block 192, where normal production should be 12,000 bbl/d gross; however, oil production is lower as operational reactivation was on January 31, 2017.*

(in boe/d)	Q1 2017	Q4 2016	Q1 2016
D&P crude oil and natural gas production	70,992	68,011	140,911
E&E crude oil and natural gas production	1,532	1,421	1,426
Total crude oil and natural gas production	**72,524**	**69,432**	**142,337**
Crude oil inventory (build) draw	(1,346)	(953)	(22,369)
Average daily sales of produced crude oil and natural gas	**71,178**	**68,479**	**119,968**
Crude oil purchased	6,533	2,544	1,777
Sales from E&E assets	(1,455)	(1,370)	(1,178)
Volume sold oil and gas including trading	**76,256**	**69,653**	**120,567**

During the first quarter of 2017, net production after royalties and internal consumption totalled 72,524 boe/d, representing an increase of 4% compared with the fourth quarter of 2016. Drilling reactivation at the Company's heavy oil fields and incremental production from Block 192 in Peru were the main drivers for increased production in the quarter. The first quarter production decreased 69,813 boe/d (49%) from the average net production of 142,337 boe/d reported in the same period of 2016, mainly attributable to the expiration of the Rubiales-Piriri contract on June 30, 2016 (27%), and as a result of lower drilling activity, natural decline operational issues related to water disposal capacity experienced throughout 2016 (22%).

Colombia

The Company continues to operate fields and facilities to maximize production while investing in impactful capital projects. Net production after royalties in Colombia for the first quarter of 2017 was 68,669 boe/d (96,765 boe/d total field production), down from 136,253 boe/d in the same period of 2016.

During the first quarter of 2017, heavy oil production from Quifa SW and other fields increased by 12% in comparison with the fourth quarter of 2016. During the first quarter of 2017, 21 development wells were drilled in the Quifa SW and CPE-6 fields. Light and medium net oil and gas production in Colombia totalled 40,666 bbl/d, decreasing by 4% compared with the fourth quarter of 2016 (42,385 bbl/d). During the first quarter of 2017, five development wells were drilled in the Cubiro, Guatiquia, and Orito blocks.

Peru

The Company's production from Peru consists of a 49% participating interest in Block Z-1, a 30% participating interest in Block 131 (blocks held for sale; please refer to Cepsa operational highlight on page 3), and an 84% participating interest in the services contract of the Block 192. Net production after royalties for the first quarter of 2017 totalled 3,855 bbl/d, a 37% decrease from 6,084 bbl/d in the same period of 2016.

In February 2016, operations in Block 192 were suspended due to problems in the NorPeruano pipeline; operations were reactivated on January 31, 2017, with an average net production in February 2017 of 1,771 bbl/d, and in March 2017 of 3,886 bbl/d (5,323 bbl/d average gross production). Production continues to ramp up at Block 192.

Inventory Movement

	2017	2016			
(in boe/d)	Q1	Q4	Q3	Q2	Q1
Crude oil inventory - beginning of the period	2,610	4,328	15,195	3,919	820
Crude oil and natural gas production	72,524	69,432	75,096	127,951	142,337
Crude oil and natural gas sales D&P (including trading)	(76,256)	(69,653)	(82,167)	(110,024)	(120,567)
Crude oil and natural gas sales E&E	(1,455)	(1,370)	(1,483)	(1,078)	(1,178)
Crude oil purchased	6,533	2,544	743	166	1,777
Overlift movement	1,505	(16)	38	(166)	(14,752)
Operational Consumption	(1,699)	(2,054)	(1,528)	(3,610)	(2,591)
Volumetric compensation	(522)	(601)	(1,566)	(1,963)	(1,927)
Crude oil inventory - end of period	**3,240**	**2,610**	**4,328**	**15,195**	**3,919**

Sales

(in thousands of US$)	Three Months Ended March 31 2017	2016
Net crude oil and gas sales and other income	$ 293,806	$ 294,269
Hedge	(8,786)	161,566
Overlift	6,347	81
Trading revenue	25,271	915
Total sales	**$ 316,638**	**$ 456,831**
Total sales excluding trading revenue	291,367	455,916
$/per volume sold	45.95	41.67

Total sales during the first quarter of 2017 were $316.6 million, 31% lower than the same period of 2016, which had revenues of $456.8 million. This decrease is explained mainly by the expiration of the Rubiales-Piriri contract on June 30, 2016 offset by better combined realized price after hedging.

The following is an analysis of the price and sales volume movements for the first quarter of 2017 in comparison with the same period of 2016:

(in thousands of US$)	Q1 2017 - 2016
Total sales for the quarter ended March 31, 2016	$ 456,831
Decrease due to lower produced and sold volume by 42% (49,768 boe/d)	(186,538)
Increase due to higher volume of trading by 5,457 bbl/d	14,208
Overlift	6,266
Hedge effect	(170,352)
Increase due to higher realized prices by 10%	196,223
Total sales for the three months ended March 31, 2017	**$ 316,638**

Realized and Reference Prices

	Three Months Ended March 31 2017	2016
Reference prices		
WTI NYMEX ($/bbl)	51.78	33.63
ICE BRENT ($/bbl)	54.57	35.21
Henry Hub average natural gas price ($/MMBtu)	3.06	1.98
Realized prices		
Oil realized price ($/bbl)	48.30	43.20
Gas realized price ($/boe)	21.29	25.29
Combined realized price oil and gas $/boe (excluding trading)	47.34	26.90
Realized hedging gain (loss) $/boe	(1.39)	14.77
Combined Realized price after hedging $/boe	**45.95**	**41.67**

Average crude oil and gas combined realized price for the three months ended March 31, 2017 reached $45.95/boe, $4.28/boe higher compared with the same period of 2016. During the first quarter of 2017, the WTI NYMEX price increased by $18.15/bbl (54%) to an average of $51.78/bbl compared with the average of $33.63/bbl in the same period of 2016. Likewise, the ICE BRENT price increased by $19.36/bbl (55%) to an average of $54.57/bbl compared with the average of $35.21/bbl in the same period of 2016.

Trading Netback

	Three Months Ended March 31	
	2017	2016
Average daily volume sold (bbl/d)	**5,804**	**347**
Operating netback ($/bbl)		
Crude oil traded sales price	$ 48.38	$ 28.95
Cost of purchases of crude oil traded	47.81	26.61
Operating netback crude oil trading ($/bbl)	**$ 0.57**	**$ 2.34**

In the first quarter of 2017, the Company traded an average of 5,804 bbl/d compared with 347 bbl/d in the same period of 2016. The average netback for volumes traded in the first quarter of 2017 was $0.57/bbl compared with the netback obtained in the same period of 2016 of $2.34/bbl.

The nature of the Company's oil trading business is opportunistic and often depends on the available capacity under the Company's 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 transportation fees.

Operating Costs

	Three Months Ended March 31	
(in thousands of US$)	2017	2016
Production costs	$ 67,400	$ 96,953
$/per boe D&P production	10.55	7.56
Transportation costs	91,252	150,787
$/per boe D&P production	14.28	11.76
Diluent cost	6,869	25,999
$/per boe D&P production	1.08	2.03
Total operating cost	**$ 165,521**	**$ 273,739**
Average operating cost per boe	**$ 25.91**	**$ 21.35**
Take-or-pay fees on disrupted transport capacity Bicentenario	27,100	25,391
$/per boe D&P production	4.24	1.98
Trading purchase cost	24,972	841
$/per bbl trading	47.81	26.61
Other costs (1)	(411)	(5,976)
Overlift / (underlift)	6,408	(34,690)
Total cost	**$ 223,590**	**$ 259,305**

1. *Other costs mainly correspond to inventory fluctuation.*

Total operating costs for the first quarter of 2017 were $165.5 million, a 40% decrease from the $273.7 million in the same period of 2016, mainly due to the expiry of the Rubiales-Piriri contract.

During the first quarter of 2017, the Company has reactivated the oil trading business, taking advantage of its transportation capacity and stronger financial position which allows for better negotiations with suppliers.

Depletion, Depreciation and Amortization

(in thousands of US$)	Three Months Ended March 31 2017		Three Months Ended March 31 2016	
Depletion, depreciation and amortization	$	101,794	$	230,592
$/per boe D&P production		15.93		17.98

Depletion, depreciation and amortization decreased to $101.8 million in the first quarter of 2017 compared with $230.6 million in the same period of 2016. This 56% decrease is mainly due to the accelerated depletion of the Rubiales-Piriri contract in 2016, the lower depletable base after the impairments recognized in 2016, and a change in the depletion calculation over the Company's proved and probable reserves in 2017 (2016: proved reserves). Unit DD&A for the first quarter of 2017 was $15.93/boe or 11% lower than the same period of 2016.

Impairment and Impairment Reversal

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

During the three months ended March 31, 2017, the Company transferred certain assets to "held for sale." In assessing the fair value of those assets, the Company reversed the following impairment charges previously recognized: exploration and evaluation assets in the Peru CGU by $10.3 million and oil and gas properties in the Colombia Central CGU by $1.3 million. The majority of the reversal relates to evidence of each asset's recoverable value in excess of the asset retirement obligation being assumed by the third party on the expected closing of each transaction.

During the first quarter of 2016, the Company determined there was an indication of impairment as at March 31, 2016. The Company performed a test of impairment and, based on the result of the test, recorded an impairment charge of $666.9 million as of March 31, 2016.

The table below summarizes the net impairment charges for the three months ended March 31:

(in thousands of US$)	Three Months Ended March 31 2017		Three Months Ended March 31 2016	
(Recovery) impairment of oil & gas properties and plant and equipment	$	(1,263)	$	603,998
(Recovery) impairment of exploration and evaluation assets		(10,362)		10,053
Impairment of other assets:				
Advances		-		11,621
Bicentenario prepayments		-		40,974
CGX loan and taxes		1,178		252
Total impairment and exploration expenses	**$**	**(10,447)**	**$**	**666,898**

General and Administrative Costs

(in thousands of US$)	Three Months Ended March 31 2017	2016
General and administrative costs	$ 27,706	$ 32,853
$/per boe D&P production	4.34	2.56

G&A costs, excluding severance and restructuring costs, decreased to $27.7 million in the first quarter of 2017 from $32.9 million in the same period of 2016, mainly due to continuing efforts to minimize discretionary spending and ongoing headcount reduction. G&A costs per boe increased by $1.78/boe to $4.34/boe from $2.56/boe in the same period of 2016 due to lower production volumes. G&A costs per boe decreased by $2.00/boe compared with the fourth quarter of 2016 to $4.34/boe from $6.34/boe.

Restructuring and Severance Costs

(in thousands of US$)	Three Months Ended March 31 2017	2016
Restructuring cost	$ -	$ 16,780
Severance	5,946	961
Total restructuring and severance costs	**$ 5,946**	**$ 17,741**

For the three months ended March 31, 2017, the Company incurred $5.9 million in costs related to severance and restructuring costs, lower than the $17.7 million for the same period of 2016.

Finance Costs

(in thousands of US$)	Three Months Ended March 31 2017	2016
Cash finance costs	$ 6,250	$ 71,277
Non-cash finance income	(1,353)	(2,363)
Total finance costs	**$ 4,897**	**$ 68,914**

Finance costs include interest on the Company’s long-term debts, working capital loans, finance leases, and fees on letters of credit, net of interest income received.

During the first quarter of 2017, finance costs decreased to $4.9 million from $68.9 million in the same period of 2016, mainly due to the change in the Company’s capital structure reducing financial debt to $250.0 million as part of the Restructuring Transaction.

Share of Gain of Equity-Accounted Investees

(in thousands of US$)	Three Months Ended March 31 2017	2016
Share of gain of equity-accounted investees - pipelines	$ 13,380	$ 15,949
Share of gain of equity-accounted investees other than pipelines	10,608	10,898
Total share of gain of equity-accounted investees	**$ 23,988**	**$ 26,847**

During the first quarter of 2017, the Company’s share of gain of equity-accounted investees decreased to $24.0 million from the $26.8 million gain in the same period of 2016, mainly due to lower gain from Pacific Infrastructure and other non-pipeline investees related to foreign exchange fluctuations.

Foreign Exchange

(in thousands of US$)	Three Months Ended March 31 2017	2016
Foreign exchange gain (loss)	$ 11,246	$ (3,339)

Foreign exchange gains or losses primarily result from the movement of the Colombian peso ("**COP**") against the U.S. dollar. A significant portion of the Company's working capital and expenditures are denominated in COP. During the first quarter of 2017 and 2016, the COP appreciated against the U.S. dollar by 4% (foreign exchange close rates from COP – U.S. dollar were COP$2,880.24 for the first quarter of 2017 and COP$3,022.35 for the first quarter of 2016). The foreign exchange gain in the first quarter of 2017 was $11.2 million compared with a loss of $3.3 million in the same period of 2016 and was primarily due to the impact the appreciation of the COP had on the translation of the Company's net working capital.

Gain (Loss) on Risk Management

(in thousands of US$)	Three Months Ended March 31 2017	2016
Gain (Loss) on Risk Mangement	$ 40,145	$ (113,545)

During the first quarter of 2017, the Company entered into several oil price risk management contracts to hedge against oil price volatility; as of March 31, 2017 the Company had hedges for production up to November 2017. The hedging portfolio consists of zero-cost collar instruments. As of March 31, 2017, the Company had outstanding finance hedge positions for approximately 8.8 MMbbl of oil with floor and ceiling strike prices of $50.87/bbl and $59.54/bbl ICE Brent, respectively, with a net asset of $8.4 million.

In addition to derivative contracts, on December 15, 2016 the Company also entered into a forward-sale contract whereby the Company shall deliver 500,000 bbl per month from June 2017 to July 2017 with a floor price of $50.00/bbl and a ceiling price of $54.00/bbl on ICE Brent.

None of the risk management contracts outstanding as of March 31, 2017 have been designated as accounting hedges. As of today, the Company has continued to actively engage in building new hedging positions for 2017, progressively closing volumes of up to 1.4 MMbbl per month to mitigate lower exposure to a downturn in oil prices.

Income Tax Expense

(in thousands of US$)	Three Months Ended March 31 2017	2016
Current income tax expense	$ (10,034)	$ (11,494)
Deferred income tax recovery: Relating to origination and reversal of temporary differences	-	1,546
Total income tax expense	**$ (10,034)**	**$ (9,948)**

Current income tax totalled $10.0 million for the three months ended March 31, 2017 as compared with $11.5 million in the same period of 2016. The variation is mainly attributable to the decrease in profits before tax in the Colombian entities, which are subject to a minimum income tax (presumptive income). The income tax for the first quarter is composed of $9.1 million of current tax in Colombia and a write-off of the income tax receivables for $0.9 million.

The 2017 Colombian wealth tax to be paid totals $11.7 million.

For more information please refer to Note 6: Income Tax in the Interim Condensed Consolidated Financial Statements.

Capital Expenditures

(in thousands of US$)	Three Months Ended March 31 2017	2016
Production facilities	$ 1,420	$ 4,447
Exploration activities	971	2,124
Development drilling	35,117	8,966
Other projects	70	3,267
Total capital expenditures	**$ 37,578**	**$ 18,804**

Capital expenditures during the first quarter of 2017 totalled $37.6 million, compared with $18.8 million in the first quarter of 2016. During the first quarter of 2017, a total of $1.4 million was invested in the expansion and construction of production infrastructure, primarily in the Cajua, Guatiquia and Neiva fields; $1.0 million was invested in exploration activities, mainly in Peru and Colombia; and $35.1 million went into development drilling, mainly in Quifa SW, Guatiquia, Orito, Cubiro, Corcel, Casimena and Arrendajo. The Company's capital expenditure program's emphasis is to narrow its geographic focus and reducing organizational scale, complexity and cost.

Selected Quarterly Information

	2017	2016				2015		
(in thousands of US$ except as noted)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Financial and Operational results:								
Average daily oil and natural gas production (boe/d)	72,524	69,432	75,096	127,951	142,337	159,831	152,915	152,428
Average daily oil production (boe/d)	66,035	62,229	67,128	118,526	131,856	149,368	143,028	144,455
Average daily natural gas production (boe/d)	6,489	7,203	7,968	9,425	10,481	10,463	9,887	7,973
Net oil and natural gas sales (boe/d)	70,452	67,470	81,877	109,736	120,220	171,039	139,270	132,417
Combined realized sales price – oil and natural gas ($/boe)	45.95	41.92	40.83	37.60	41.67	41.22	51.49	53.72
Realized oil and gas price ($/boe)	47.34	43.44	40.83	37.60	26.90	32.75	41.70	55.35
Realized oil hedging ($/boe)	(1.39)	(1.52)	0.00	0.00	14.77	8.47	9.79	(1.63)
ICE BRENT ($/bbl)	54.57	51.06	46.99	47.03	35.21	44.69	51.30	63.50
Operating cost ($/boe)	25.91	(27.98)	(24.54)	(20.53)	(21.35)	(22.01)	(20.93)	(22.30)
Operating netback crude oil and gas ($/boe)	20.04	13.94	16.29	17.07	20.32	19.21	30.56	31.42
Consolidated netback crude oil and gas ($/boe)	17.89	13.30	12.35	17.01	19.58	17.41	27.93	30.14
Cash netback crude oil and gas ($/boe)	12.57	5.46	4.77	11.47	11.46	9.70	19.51	21.06
Net sales ($)	316,638	269,772	308,705	376,403	456,831	651,970	669,995	702,733
Net income (loss) attributable to equity holders of the parent for the period ($)	8,498	4,025,194	(557,068)	(118,654)	(900,949)	(3,895,908)	(617,318)	(226,377)
- basic ($)	0.17	80.50	(176,835.08)	(37,665.40)	(285,996.31)	(12.37)	(1.97)	(0.72)
Operating EBITDA ($)	92,442	44,275	89,846	120,452	190,064	224,911	331,974	335,235
Consolidated EBITDA ($)	115,057	(1,967)	37,689	126,083	91,814	257,584	414,550	196,592
Capital expenditures ($)	37,578	64,248	30,061	48,349	18,804	160,154	154,281	185,043
Total assets (end of period) ($)	2,772,423	2,741,719	2,403,602	2,990,699	2,687,858	3,986,121	8,290,772	9,376,943

Non-IFRS Measures

This report contains the following financial terms that are not considered in IFRS: Operating and Consolidated EBITDA, and Operating, Consolidated and Cash Netback. 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 measures should not be considered in isolation or as a substitute for measures of performance prepared in accordance with IFRS. These financial measures are included because management uses this information to analyze operating performance and liquidity. They are different from those measures disclosed in prior periods, reflecting the Company's new strategic focus on operational efficiency and capital discipline.

Operating and Consolidated EBITDA

Management believes that EBITDA is a common measure used to assess profitability before the impact of different financing methods, income taxes, depreciation and impairment of capital assets, and amortization of intangible assets.

- Operating EBITDA represents the operating results of the Company's primary business, excluding the effects of capital structure, other investments (infrastructure assets), non-cash items that depend on accounting policy choices, and one-time items that are not expected to recur.
- Consolidated EBITDA excludes items of a non-recurring nature (one-time items) or that could make the period-over-period comparison of results from operations less meaningful, but includes results from the Company's other investments (infrastructure assets).

A reconciliation of Operating and Consolidated EBITDA to Net Income is as follows:

	Three Months Ended March 31	
(in thousands of US$)	2017	2016
Net income (loss) [(1)]	**$ 8,497**	**$ (900,949)**
Adjustments		
Income tax expense	10,034	9,948
Depletion, depreciation and amortization	101,795	230,592
Impairment and exploration (income) expenses	(10,447)	666,898
Finance costs	4,897	68,914
Restructuring and severance costs	5,946	17,741
Equity tax	11,694	26,901
Other income	(2,498)	(42,210)
Foreign exchange unrealized (gain) loss	(14,861)	13,979
Consolidated EBITDA	**115,057**	**91,814**
(Gain) loss valuation of unrealized hedge contracts	(40,145)	113,545
Share of gain in equity-accounted investees	(23,988)	(26,847)
Gain attributable to non-controlling interest	10,783	7
Share based compensation loss (gain)	20	(3,206)
Foreign exchange realized loss (gain)	3,615	(10,640)
Fees paid on suspended pipeline capacity	27,100	25,391
Operating EBITDA	**$ 92,442**	**$ 190,064**

1. *Net income (loss) attributable to equity holders of the parent.*

Netbacks

Management believes that Netback is a useful measure to assess the net profit after subtracting all the costs associated with bringing one barrel of oil to the market. It is also commonly used by the oil and gas industry to analyze financial and operating performance expressed as profit per barrel.

- Operating Netback represents realized price per barrel plus realized gain or loss on financial derivatives, less production, transportation, and diluent costs, and shows how efficient the Company is at extracting and selling its product.
- Consolidated Netback represents Operating Netback plus the results from corporate investments such as our pipeline investments that are in addition to oil and gas production and the take-or-pay tariffs paid on disrupted pipelines.
- Cash Netback represents Consolidated Netback less corporate cash expenses (general and administrative expenses and cash finance costs).

Refer to "Netbacks" on page 6.

Financial Position

Upon completion of the Restructuring Transaction and as of March 31, 2017, the only long-term borrowing of the Company consisted of the five-year Senior Secured Notes due 2021 bearing interest at 10% per annum.

Covenant/Limitation on Indebtedness

Under the indenture for the Senior Secured Notes due in 2021 (the "**Indenture**"), the Company may not incur, with some exceptions, directly or indirectly, any additional indebtedness prior to November 2, 2018. Subsequent to November 2, 2018, and after giving effect to certain conditions provided under the Indenture, the Company may incur additional indebtedness provided that the Company complies with the following financial covenants:

Covenant	**Ratio**
Consolidated Debt to Consolidated Adjusted EBITDA (1)	2.50
Consolidated Fixed Charge (2)	3.25

1. *Consolidated Debt to Consolidated Adjusted EBITDA Ratio is defined in the Indenture as the consolidated total indebtedness as of such date divided by Consolidated Adjusted EBITDA on a last-twelve-months basis. Consolidated Adjusted EBITDA is defined as the consolidated net income plus: i) interest expense; ii) income tax and equity tax; iii) depletion and depreciation expense; iv) amortization expense; and v) impairment charge, exploration expense and abandonment costs.*
2. *Consolidated Fixed Charge Ratio means at any date, the result of dividing the Consolidated Adjusted EBITDA for the most recent ended period of four consecutive fiscal quarters and the consolidated interest expense for such period.*

Other covenants under the Indenture limit, with some exceptions, the Company's ability to sell assets, incur liens, and enter into lease-back transactions, among others.

Letters of Credit

As at March 31, 2017, the Company had issued letters of credit facilities and guarantees for exploration and operational commitments for a total of approximately $156.3 million.

Outstanding Share Data

Common shares

As at May 4, 2017, 50,002,363 common shares were issued and outstanding.

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

Deferred share units

As at May 4, 2017, there were 30,542 DSUs outstanding. DSUs are instruments that may be settled in cash or common shares that track the price of the common shares and are payable to eligible participants (being limited to directors of the Company) upon their departure from the Board of Directors of the Company.

Liquidity and capital resources

As at March 31, 2017, the Company had positive working capital of $280.1 million, comprised of $470.0 million in cash and cash equivalents, $37.1 million in restricted cash, $235.9 million in accounts receivable, $38.9 million in inventory, $57.2 million in income tax receivable, $2.1 million in prepaid expenses, $43.4 million in assets held for sale, $8.4 million in risk management assets, $586.7 million in accounts payable and accrued liabilities, $0.3 million in risk management liability, $4.1 million in income tax payable, $3.8 million in the current portion of obligations under finance lease, and $18.0 million in asset retirement obligations.

Refer to “Risks and Uncertainties” on page 24 for details of the risks and uncertainties relating to the Company’s liquidity and capital resources.

4. Commitments and Contingencies

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

Tax Review in Colombia

The Dirección de Impuestos y Aduanas Nacionales ("**DIAN**") is 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, 2017, the DIAN has reassessed $59.7 million of tax owing, including estimated interest and penalties, with respect to the denied deductions.

As at March 31, 2017, 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 consolidated financial statements.

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% capacity right in the OCENSA pipeline in Colombia. Under the assignment agreement, the Company is entitled to use Transporte Incorporado's capacity to transport crude oil through the OCENSA pipeline for a set monthly premium until 2024. Pursuant to the assignment agreement, the Company is required for the duration of the agreement to maintain a minimum credit rating of Ba3 (Moody's), which was breached in September and December 2015 and January 2016 when Moody's downgraded the Company's credit rating to B3, Caa3, and C, respectively. As a result of the downgrade and in accordance with the assignment agreement, upon giving notice to the Company, Transporte Incorporado would have the right to early-terminate the assignment agreement, and the Company would be required to pay an amount determined in accordance with the agreement, estimated at $102.8 million. The Company did not receive such notice from Transporte Incorporado, and on January 6, 2016 the Company received a waiver from Transporte Incorporado of its right to early-terminate for a period of 45 days until February 15, 2016, which was further extended several times to March 31, 2019. The Company continues to pay monthly premiums. No provision has been recognized as at March 31, 2017 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 2017. As part of the expansion project, the Company, through its subsidiaries Meta Petroleum and Petrominerales Colombia, entered into separate crude oil transport agreements with OCENSA for future transport capacity. The Company will start paying ship-or-pay fees once the expansion project is complete and operational. As part of the transport agreements, the Company is required to maintain minimum credit ratings of BB- (Fitch) and Ba3 (Moody's). This covenant was breached in September and December 2015 and January 2016 when Moody's downgraded the Company's credit rating to B3, Caa3, and C, respectively. As a result of the downgrades and pursuant to the transport agreements, upon giving notice to the Company, OCENSA has the right to require the Company to provide a letter of credit or proof of sufficient equity or working capital within a cure period of 60 days starting from the day on which notice is received by the Company.

On November 5, 2015, the Company received a waiver from OCENSA of its right to receive a letter of credit, which will expire once the project is complete and operational.

The relevant transportation contracts also provide for the possibility of the Company providing evidence to OCENSA of compliance with the liquid assets and working capital tests, which evidence was submitted to OCENSA upon completion of the 2016 financial statements. The Company has also improved its credit rating to B stable (Fitch, Standard & Poor's) post-emergence.

Commitments

Disclosures concerning the Company's significant commitments can be found in Note 18 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 21 to the Interim Condensed Consolidated Financial Statements.

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 and Cajua fields is 60%. However, this participation may change monthly as a function of the PAP formula stipulated in the Quifa Association Contract.

Carrizales Field (Cravoviejo Block)

On April 27, 2013, 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 Cravoviejo E&P 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.

Zopilote Field (Cravoviejo Block)

In April 2015, the exploitation area of the Zopilote field reached five million barrels in accumulated production of oil, activating the ANH rights on additional PAP pursuant to the Cravoviejo E&P contract. According to the contract terms, this additional participation share from the Zopilote field is payable either in cash or in kind and has been accounted for as part of the operating cost for this field.

PAP Disagreement with the ANH

The Company has certain exploration contracts acquired through business acquisitions where there existed outstanding disagreements with the ANH relating to the interpretation of the high-price participation clause. These contracts require high-price participation payments to be paid to the ANH once an exploitation area within a contracted area has cumulatively produced five million or more barrels of oil. The disagreement 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 E&P 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 in 2013 and which is the only one for which an arbitration process has been initiated. However, the arbitration process for Corcel was suspended at the time the Company acquired Petrominerales.

As at March 31, 2017, the amount under arbitration is approximately $195.4 million plus related interest of $49.0 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 U.S. dollars, 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%.

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

5. 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 Company's internal audit and legal compliance departments 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 terms and conditions of the related parties' transactions are included in the annual financial statements as at December 31, 2016; no changes occurred during the three months ended March 31, 2017.

The following table provides the total amount of transactions that have been entered into with related parties during the three months ended March 31, 2017 and 2016, as well as balances and commitments with related parties as at March 31, 2017 and December 31, 2016:

		Sales	Purchases / Services	Accounts Receivables	Accounts Payables	Commitments
Oleoducto de los Llanos (ODL)	2017	$ -	$ 8,787	$ 1,427	$ 5,522	$ 163,697
	2016	93	29,649	638	341	176,442
Oleoducto Bicentenario de Colombia S.A.S	2017	-	32,276	12,437	-	1,008,823
	2016	-	50,251	13,400	-	1,164,251
Pacific Infrastructure Ventures Inc.-Sociedad Portuaria Puerto Bahia S.A [1]	2017	-	9,989	862	1,326	181,320
	2016	2,083	10,241	828	905	199,859
Interamerican Energy - Consorcio Genser Power - Proelectrica	2017	331	-	328	556	-
	2016	5,986	5,988	174	555	-
Paye Foundation [2]	2017	-	1,715	-	67	-
	2016	-	3,557	-	1,737	-
Fupepco Foundation	2017	-	44	45	7	-

The following table provides the interest recognized during the three months ended March 31, 2017 and 2016, as well as the loans and interest balance outstanding from related parties as at March 31, 2017 and December 31, 2016:

		Cash Advance	Loans	Interest Balance	Interest Income	Convertible Debentures
Oleoducto Bicentenario de Colombia S.A.S [3]	2017	$ 87,753	$ -	$ -	$ -	$ -
	2016	87,753	-	-	-	-
Pacific Infrastructure Ventures Inc. [1][3]	2017	-	76,551	20,084	1,987	-
	2016	-	74,279	18,097	1,264	-
CGX Energy Inc. [3]	2017	-	10,986	1,500	-	1,500
	2016	-	10,000	1,500	-	1,500

1. *Please refer to Note 14: Other Assets from the Interim Condensed Consolidated Financial Statements.*
2. *Formerly Pacific Rubiales Foundation.*
3. *The Company recorded impairment charges related to certain amounts that may not be recoverable.*

On April 26, 2017, the Company entered into a bridge loan facility with CGX. The principal amount of up to $3.1 million, is divided into tranches, payable within 12 months of the first draw-down. The loan carries an annual interest rate of 5%.

6. Accounting Policies, Critical Judgments, and Estimates

Basis of Presentation

The Interim Condensed Consolidated Financial Statements for the three months ended March 31, 2017 have been prepared in accordance with IAS 34 Interim Financial Reporting.

The Interim Condensed Consolidated Financial Statements do not include all the information and disclosures required in the annual financial statements and should be read in conjunction with the Company's annual financial statements as at December 31, 2016.

Significant Accounting Judgments, Estimates and Assumptions

Estimation Uncertainty and Assumptions

Oil and gas properties

Oil and gas properties are depreciated using the unit-of-production method. Starting January 1, 2017, in applying the unit-of-production method, oil and gas properties were depleted over proved and probable reserves; this is contrasted with 2016, when they were depleted over proved reserves. This change is a result of the Company's ability to finance its near-term capital programs included in the updated reserve estimates. The calculation of the unit-of-production rate of amortization could be impacted to the extent that actual production in the future is different from current forecasted production based on proved and probable reserves. This would generally result from significant changes in any of the following:

- Changes in reserves;
- The effect on reserves of differences between actual commodity prices and commodity price assumptions; or
- Unforeseen operational issues.

Changes in Accounting Policies and Disclosures

The accounting policies adopted in preparation of the interim condensed consolidated financial statements are consistent with those disclosed in the Company's annual consolidated financial statements for the year ended December 31, 2016, except for the adoption of minor amendments and interpretations effective January 1, 2017. These amendments and interpretations had little or no impact on the interim condensed consolidated financial statements. The Company has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective.

Standards Issued but Not Yet Effective

Standards issued but not yet effective up to the date of issuance of the Company's interim financial statements that are likely to have an impact on the Company are consistent with those followed in the preparation of the Company's annual consolidated financial statements for the year ended December 31, 2016. The Company intends to adopt these standards when they become effective. A summary of the standards is below.

IFRS 2 Classification and Measurement of Share-based Payment Transactions

The Company plans to adopt the new standard as of the effective date and is in the process of assessing the impact on its consolidated financial statements. The amendments are effective for annual periods beginning on or after January 1, 2018.

IFRS 9 Financial Instruments

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

IFRS 15 Revenue from Contracts with Customers

The Company plans to adopt the new standard as of the effective date and is in the process of assessing the impact on its consolidated financial statements. The standard is effective for annual periods beginning on or after January 1, 2018.

The Company is evaluating by each legal entity and for each contract identified, using the five-step model included in IFRS 15. The analysis includes the investments in associates in order, to have a full inventory of all contracts on each legal entity. Additionally, the disclosures required by the standard, are being reviewed.

IFRS 16 Leases

The Company plans to adopt the new standard as of the effective date and is in the process of assessing the impact on its consolidated financial statements. The standard is effective for annual periods beginning on or after January 1, 2019.

7. Internal Control - Risks and Uncertainties

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 annually issues a "Certification of Annual Filings." This Certification requires certifying officers to certify, among other things, that they are responsible for establishing and maintaining Disclosure Controls and Procedures ("**DC&P**") and Internal Controls Over Financial Reporting ("**ICFR**") as those terms are defined in NI 52-109.

The Company's ICFR are 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 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 first quarter of 2017, the internal audit department of the Company completed an updated risk analysis, identifying 208 key controls classified as ICFR and DC&P. The internal audit department implemented a control self-assessment evaluation of the 208 controls and established a direct testing program for 41 of the 208 controls. The CSA evaluation and direct testing are in process.

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

- 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
- Information required to be disclosed by the Company in its annual filings, interim filings, and other reports filed or submitted by the Company under securities legislation is recorded, processed, summarized, and reported within the time period specified in securities legislation.

During 2016 the Board of Directors appointed a new Chief Financial Officer who assumed the position as of December 1, 2016. One of the primary duties of the Chief Financial Officer is to maintain and continue to strengthen the Company's ICFR. 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 include, but are not limited to:

- The concentration of a significant percentage of the Company's Common Shares in the hands of a few holders;
- The recent appointment of the Board of Directors, who are still gaining experience with respect to the Company's operations;
- Recent changes to the Company's management structure, which may undergo further changes;
- Volatility in market prices for oil and natural gas;
- A continued depressed oil and natural gas price environment with the potential of further decline;
- The riskiness of exploration for oil and natural gas, which may not be commercially successful, impairing the Company's ability to generate revenues from its operations;
- The potential ineffectiveness or unintended consequences of the Company's ongoing cost and capital expenditure reduction;
- Uncertainties associated with estimating oil and natural gas reserves;
- Disruptions in, or the increase of costs associated with, the transportation of hydrocarbons;
- The expiration of the Company's exploration and exploitation contracts and the costs associated therewith;
- Uncertainty over the ability to add reserves through exploration, acquisition, or development activities to mitigate the effect of reserves and production decline over time;
- Operating hazards and risks such as fires, explosions, mechanical failures, pipe or well cement failure, well casing collapse and the like;
- The availability of drilling and related equipment, transportation, power, and technical support in the areas where the Company's activities will be conducted;
- The costs associated with, and availability of funds for, abandoning and reclaiming wells, facilities, and pipelines that the Company uses for production of oil and gas reserves;

- The costs of compulsory work programs under the Company's exploration contracts and the penalties associated with failing to meet them;
- The impact of operating costs on net revenue;
- Uncertainties relating to the availability and costs of financing needed in the future;
- Delays in obtaining required environmental and other licences;
- The effect of global financial conditions on the Company's operations and ability to raise capital;
- The effect of ratings downgrades on the Company's business and operations;
- The effect of changes in interest rates on debt with floating rates and take-or-pay arrangements;
- The potential volatility of the trading price for the Company's Common Shares;
- Competition in the oil and gas industry for capital, acquisitions of reserves, undeveloped land, and skilled personnel, among other things;
- Risks associated with managing growth;
- The direct and indirect costs associated with labour disruptions in or around the Company's operations;
- The potential of over-concentration of the Company's customers, which can result in over-reliance on one customer or credit issues;
- The possibility of litigation relating to labour, health and safety matters, environmental matters, regulatory, tax, and administrative proceedings, governmental investigations, arbitration, and contractual claims and disputes, the results of which are difficult to predict;
- The possibility of challenges to the Company's titles or interests in its various properties;
- Fluctuations in foreign exchange or interest rates and stock market volatility;
- The possibility of disproportionate effects and costs associated with the concentration of a majority of the Company's producing properties and leases in the Llanos Basin in eastern Colombia;
- The risk of exposure to corruption given the Company's geographic range, operational diversity, and technical complexity;
- The difficulty or impossibility of enforcing judgments granted by a court in Canada against the assets of the Company or the directors and officers of the Company residing outside of Canada;
- The lack of assurance that restrictions on repatriation of earnings from Colombian subsidiaries will not be imposed in the future;
- The possibility that the Company may be unable to declare and pay dividends on its Common Shares;
- The reliance on various forms of technology for the Company's business operations, which can be subject to a variety of risks including the costs of maintaining such technology and cyber-crime, among others;
- The risks associated with operating in different geographies where social, civil unrest or security events are not within the Company's control. These actions could cause harm to our employees, contractors and business operations in which the Company has interests;
- The potential dependence of the Company's ability to operate on its ability to form and maintain strategic commercial relationships with other oil and gas operators;
- The possibility that if certain contingencies occur, they could have a material adverse effect on the Company's business, results of operations, and financial condition;
- Economic and political risks inherent in any investment in a corporation, like the Company, that operates in emerging markets;
- Guerilla and security risks in the Company's areas of operations;
- The degree of development of the oil and gas industry in the countries in which the Company operates;
- Failure to identify and effectively meet changes in regulation in all jurisdictions the Company operates;
- The effect and costs of environmental regulation in the countries in which the Company operates; and
- Risks associated with foreign exchange controls and actual or effective expropriation of assets.

Readers are cautioned that the foregoing list of factors is not exhaustive. The Company's Annual Information Form ("**AIF**") for the period ended December 31, 2016 and dated March 14, 2017 contains a more comprehensive discussion of the risks and uncertainties that could have an effect on the business and operations of the Company. The AIF is available at www.sedar.com and readers are urged to read the discussion in its entirety.

8. Further Disclosures

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.

Abbreviations

The following abbreviations are frequently used in the Company's MD&A.

1P	Proved reserves
2P	Proved reserves + Probable reserves
bbl	Barrels
bbl/d	Barrels per day
boe	Barrels of oil equivalent
boe/d	Barrels of oil equivalent per day
Mbbl	Thousand barrels
Mbbl/d	Thousand barrels per day
Mboe	Thousand barrels of oil equivalent
Mboe/d	Thousand barrels of oil equivalent per day
MMbbl	Million barrels
MMbbl/d	Million barrels of oil per day
MMboe	Million barrels of oil equivalent
WTI	West Texas Intermediate index